Canadian Oil and Gas Production in the Global Clean Energy Transition

Outlook and economic risks

TECHNICAL REPORT FOR ENVIRONMENTAL DEFENCE CANADA AND THE INTERNATIONAL INSTITUTE FOR SUSTAINABLE DEVELOPMENT

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June 2025

Written by Greg Muttitt

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The author retains responsibility for any errors or omissions.

About the Author

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Key Findings

Canada is exposed to significant economic risks due to overinvestment in oil and gas production relative to the pace of the global energy transition. Eighty-one percent of Canada's oil and 44% of Canada's gas is exported for consumption abroad. Canadian oil is, on average, expensive relative to other international producers. Canadian gas, meanwhile, faces significant barriers to access global markets as it depends either on trade with the United States—which is increasingly contentious—or new, high-cost liquefaction facilities that require high demand and high prices over the long term to be profitable.

The greater the misalignment between Canadian supply and global demand, the greater the risks to companies, government revenues, and the financial sector. Under current global policies, 5% of projected capital investment in Canadian oil and gas production (between 2025 and 2040) is expected to be "stranded" in economically uncompetitive projects. Under announced global net-zero pledges, this proportion increases to 39%, and in a scenario aligned with the Paris Agreement's target of limiting temperature rise to 1.5°C, it becomes 66%. Note that these estimates relate to the share only of future capital investments; in addition, much of the capital that has already been invested will fail to deliver commercial returns.

Limiting the expansion of supply could, perhaps counterintuitively, protect the value of Canada's oil and gas industry going forward. This report models two complementary approaches for doing so. First, Canadian governments could restrict the development of new oil and gas production projects under their jurisdiction. Second, Canada could engage in diplomatic efforts to cooperatively reduce global oil and gas production. Relative to a business-as-usual supply scenario, these two approaches could (a) reduce stranded asset risks, (b) increase related government revenue, and (c) enhance the overall value of Canada's oil and gas industry. These findings are consistent regardless of whether global climate ambition increases further; however, the economic benefits of these supply-side policy strategies would be amplified if the global energy transition accelerates.

Executive Summary

Global energy markets are changing. Most energy forecasters now project that global oil consumption will peak this decade, even if no new climate policies are introduced. This projection is driven by the rapid take-up of electric vehicles. While gas forecasts are more varied, wind and solar are now the cheapest form of power generation in most of the world, and their share of electricity supply (currently 10% globally) is rising fast, squeezing gas demand. This transition is expected to accelerate as governments introduce additional policies to meet their climate pledges.

With 81% of its oil and 44% of its gas exported, Canada faces growing economic risks as its export markets transform. At a national level, oil and gas play a significant role in the economy, while in some provinces, the sector is particularly important (Table ES1).

Table ES1. Upstream (extraction-related) oil and gas contributions to Canadian and provincial economies, 2023

	Canada	Alberta	Saskatchewan	Newfoundland & Labrador	British Columbia
Oil and gas contribution to GDP	3.0%	16.2%	8.8%	14.4%	1.5%
Oil and gas share of jobs	0.7%	5.4%	1.2%	1.4%	0.2%
Oil and gas contribution to government revenues[1]	0.7%	33%	4%	7%	1%

Source: Statistics Canada; additional details and sources are outlined in Appendix A.

Aims and Methods of This Report

This report aims to shine a light on the economic risks facing Canadian oil and gas production during the global energy transition. The analysis adapts and builds on a stranded asset[2] methodology developed by the Carbon Tracker Initiative to assess which supply projects (that is, which oil and gas fields) can competitively meet a given demand level. Oil and gas supply and

[1] Note that the provincial revenue shares include only royalties, not other sources of upstream oil and gas revenue such as corporate income tax or payments to provincial revenue funds.

[2] Stranded assets are investments that fail to achieve a commercial return due to changes in markets or policy from what was expected at the time of the investment.

investment projections are generated using the Rystad Energy UCube, an economic model of the world's oil and gas fields produced by the consultancy Rystad Energy. These projections are based on the industry's expectations of sustained oil and gas demand.

Demand projections are taken from the International Energy Agency's three main scenarios. In the Stated Policies Scenario (STEPS), the policy landscape remains as it is today. In the Announced Pledges Scenario (APS), governments that have committed to achieving net-zero emissions (NZE) by mid-century successfully do so. In the NZE scenario, governments go further and achieve the Paris Agreement goal of limiting warming to 1.5°C. Each scenario forecasts progressively lower oil and gas demand. We do not know how the future will unfold; together, these scenarios represent a range of possible futures that allows us to assess risk. Note that oil and gas demand projections in STEPS have been successively revised downward in the last few editions.

Investments in conventional oil and gas and oil sands have multi-decadal time horizons. Economic risk arises because of misalignments between expectations at the time of investment and how energy markets ultimately unfold. The risk is lower for investments in extraction by hydraulic fracturing (fracking), which have short time horizons and are more able to adapt to evolving demand and price conditions.

This report does not assess potential damage to the wider economy arising from the physical impacts of climate change. Thus, while the report highlights the economic risks from overinvesting in oil and gas production relative to the pace of the global energy transition, it should not be inferred that the economy would be better with a slower energy transition. Rather, the message is the importance of preparedness and resilience to simultaneously mitigate transition and physical risks.

Economic Impacts on Canadian Oil and Gas Production

The report finds that Canadian oil and gas production is highly vulnerable to economic risks arising from the global energy transition, with significant potential impacts on the Canadian economy. If demand follows the STEPS scenario, the risks are relatively low. As the transition moves faster, risks escalate.

- With STEPS demand, 5% of projected oil and gas capital investment from 2025 to 2040 fails to achieve commercial returns due to projects being uncompetitive.
- With APS demand, this rises to 39%; with NZE demand, it rises to 66%.

Note that these estimates do not include capital that has already been invested, much of which is also in projects that will fail to deliver commercial returns on the investment.

The net present value (NPV) of future Canadian oil and gas production is defined as the cumulative total of all future incomes and expenditures on the oil and gas fields, discounted to the present moment to account for the economic effect of time. The analysis finds the following (Figure ES1):

- In Rystad's base case, representing industry expectations, the NPV_{10} (NPV at 10% nominal discount rate) of future Canadian oil and gas production is nearly USD 480 billion.
- At equilibrium oil and gas prices associated with STEPS demand, NPV_{10} is 19% lower than this, and with APS demand, it is 77% lower (i.e., the majority of value is lost compared to expectations). This loss of value is felt in existing assets and misjudged future investments.
- With NZE demand, total NPV_{10} becomes negative: oil and gas fields are a liability rather than an asset.

NPV not only captures the value of investments, it is a key determinant in valuing oil companies. Oil and gas companies account for 16% of the investments in the Toronto Stock Exchange. Economic losses to oil companies can cause financial instability, knock-on effects in other sectors, and macroeconomic impacts such as reduced investment and output.

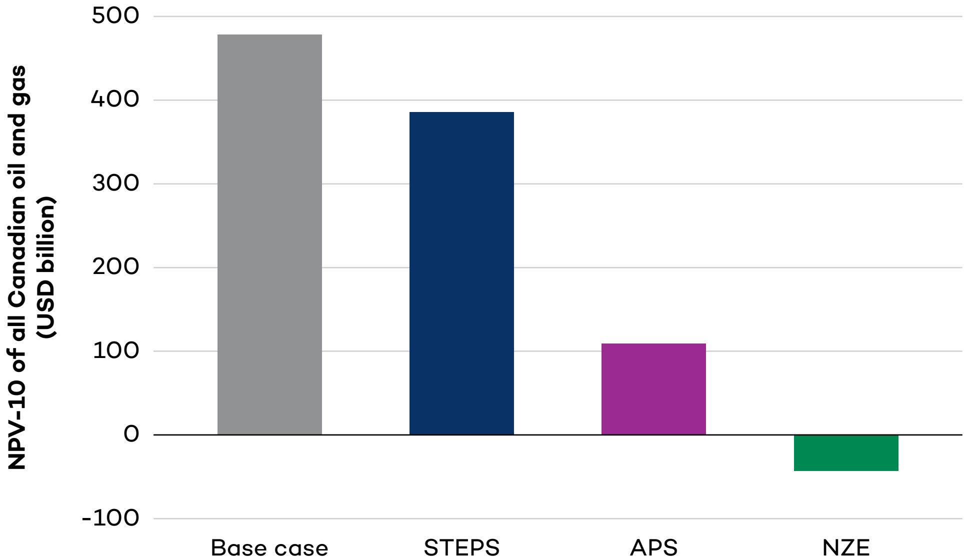
Turning to the impact on government revenues (Figure ES2):

- At STEPS demand levels, revenues are comparable to the 2022–2024 average, while they are 68% lower with APS demand and 96% lower with NZE demand.
- With NZE demand, long-term revenues are even lower (USD 1.3 billion per year) than in 2020 due to the COVID-19 pandemic (USD 2 billion).

Note that these numbers underestimate the full fiscal effects, as job losses will lead to reduced income tax payments and increased social support. Reduced profitability is also likely to create strong political pressure for greater subsidies to producers. Financial stresses in oil companies may also lead to environmental cleanup and decommissioning liabilities being left to public budgets.

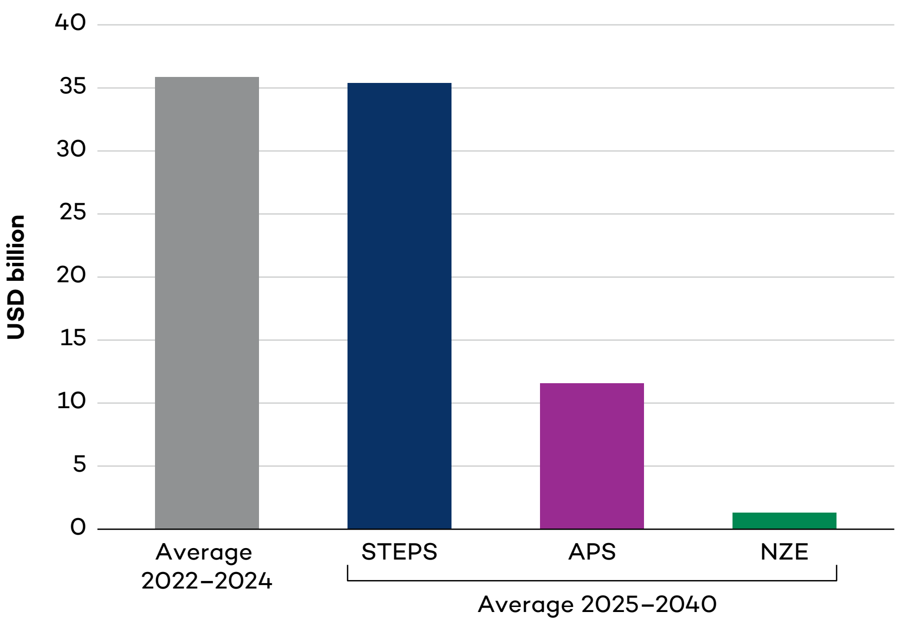
These risks to fiscal revenues highlight the importance of diversifying both sources of government revenue and the broader economic base. Investments in alternative sectors can both offset the fiscal losses and create new jobs.

Figure ES1. NPV$_{10}$ of Canadian oil and gas production at different demand levels



Source: Author's analysis, using Rystad Energy UCube, 2024.

Figure ES2. Annual average government revenues (combined federal and provincial) from Canadian oil and gas production (2025–2040) at different demand levels, compared to 2022–2024



Source: Author's analysis, using Rystad Energy UCube, 2024.

The Effect of New Oil and Gas Fields/Projects

Looking specifically at conventional fields, oil sands projects, and fracking acreages that have not yet been developed (collectively referred to here as "undeveloped fields") reveals several insights.

- At STEPS demand levels, the NPV_{10} of undeveloped fields is just 5% of the total NPV_{10} of all fields, with downside risk if demand falls below this.
- Developing new fields becomes value-destructive at average prices below USD 62/bbl. At both APS and NZE demand levels, the aggregate NPV_{10} of all undeveloped fields is negative, meaning that proceeding with new fields, on the whole, destroys rather than creates value.[3]
- At both APS and NZE demand levels, government revenues from new fields are negative: rebates and subsidies exceed tax payments for these fields, even before taking into account indirect effects.

From 2018 to 2020, the Government of Alberta prorationed oil production to combat oversupply and boost prices. While that measure responded to a temporary oversupply relative to export capacity, this report explores whether government intervention can similarly address the longer-term oversupply relative to declining global demand.

Figure ES3 shows the effects of two policy measures on NPV_{10} and government revenue. The first measure is stopping new field development at home. New field developments require approval by provincial and/or federal regulators, suggesting a possible opportunity for governments to intervene. The second measure is to leverage the example of stopping new field development at home to help persuade other countries to do the same (modelled here with a 10% success rate in the persuasion efforts).

- In all three demand scenarios, ending new field development improves NPV_{10}. With NZE demand levels, it moves NPV_{10} from negative to positive; with APS demand, it increases NPV_{10} by 44%.
- In all three scenarios, ending new field development also improves government revenues. The effect is greatest with NZE demand, where revenues increase by a factor of 2.7.
- Persuading other governments to end new field development also improves NPV_{10} and government revenues in all three scenarios. The effect is greatest with STEPS demand.

If Canada ceases to develop new fields, the remaining supply in other countries would have to meet the demand, pushing up the equilibrium price.[4] A relatively small price increase from USD 66 to USD 73/bbl improves the economics of existing fields. As a result, even at STEPS demand levels, ending new field developments improves NPV_{10} for Canada's oil and gas industry.

[3] While some individual fields might deliver positive returns, investments overall fail to generate commercial returns in these scenarios.

[4] The methodology assumes a fixed consumption level independent of price. In the real world, higher prices would lead to reduced demand, such that Canada's reduced production is only partially substituted from elsewhere.

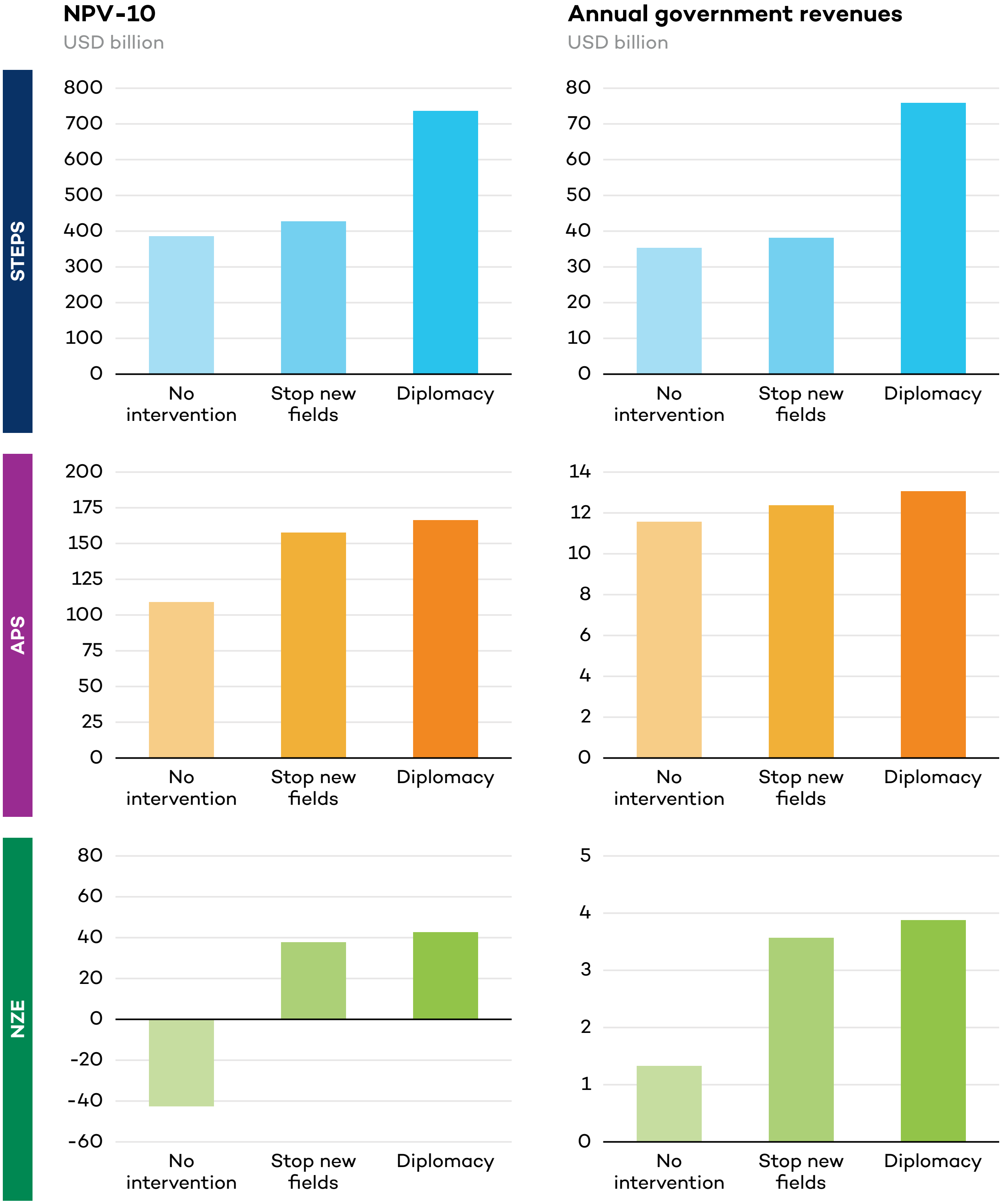
Some commentators have suggested that any reductions in Canadian supply would lead to Organisation of Petroleum Exporting Countries (OPEC) members increasing their production in its place. This report finds that prospect unlikely, however, as OPEC's economic benefit from greater volume would be outweighed by the effect of lowering prices. Simply put, it would not be in OPEC's economic interest.

These results suggest that restricting oil and gas development would protect the Canadian economy from overinvesting in soon-to-be surplus assets, regardless of whether global climate ambition increases. With STEPS demand in particular, this constitutes a collective action problem: an individual producer may gain from developing a field that has positive NPV, but the whole industry will be better off if no new fields are developed. This is because the volume effect is more important to individual producers, whereas the price effect is more important to the industry as a whole. Such a policy could also benefit the public by reducing negative impacts on the wider economy, even aside from the benefits of mitigating climate change.

If Canada also persuades some other countries to follow suit in stopping new field development, global oversupply would be reduced, avoiding price deflation and improving the economics of Canadian production. Such persuasion by setting an example is the logic behind the growing popularity of "climate clubs," where coalitions of willing governments collectively agree to adopt ambitious policies, such as the Powering Past Coal Alliance, the Clean Energy Transition Partnership, and the Beyond Oil and Gas Alliance.

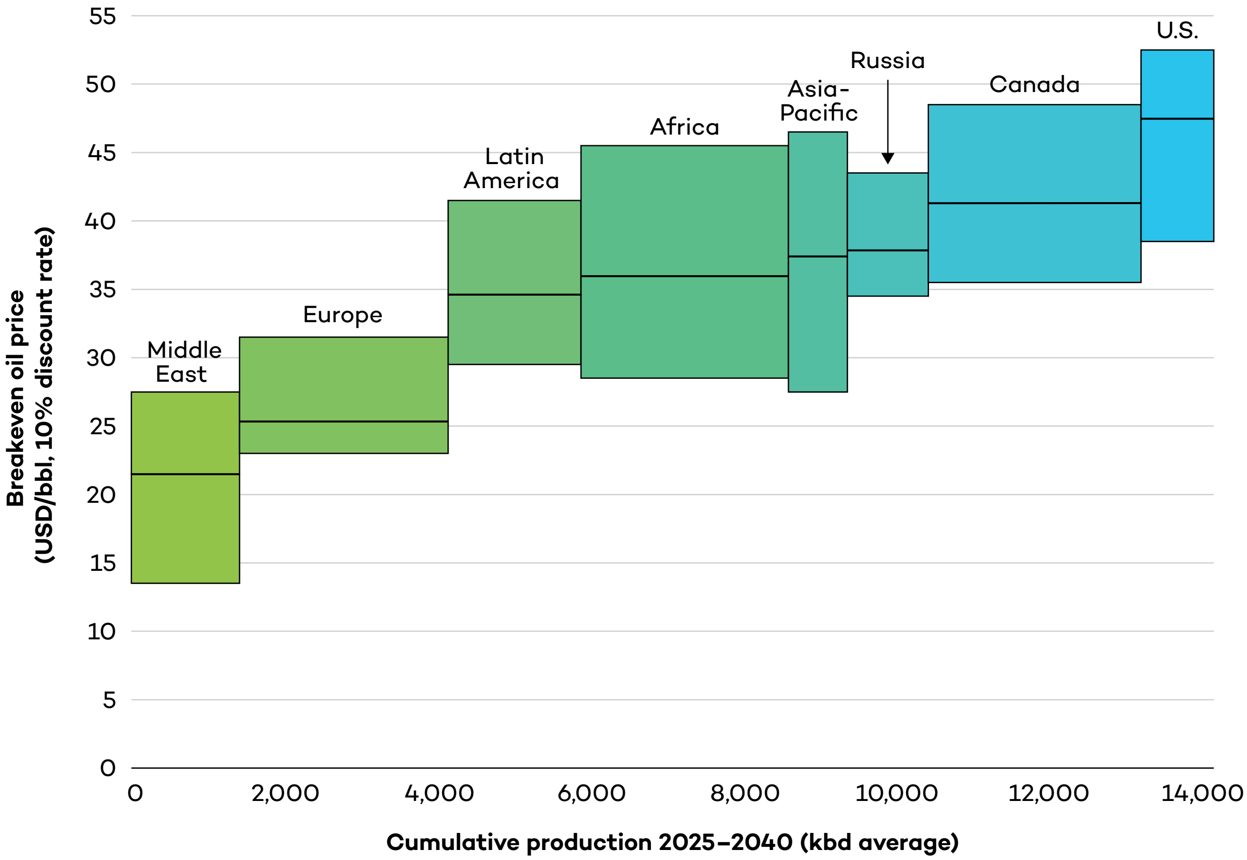
All incumbents benefit economically from environmental rules and norms that make it harder for new entrants to join the market. The benefit is especially great for producers at the high end of the cost curve, such as Canada (Figure ES4), as their returns are more vulnerable to low prices than those of low-cost producers with wider profit margins. Instead, Canada's best economic outcomes are achieved if global supply declines alongside demand.

Figure ES3. Impact of policy interventions on NPV_{10} (left-hand panels) and undiscounted average annual government revenues 2025–2040 (right-hand panels) of Canadian oil and gas production at different demand levels (in USD billion)



Source: Author's analysis, using Rystad Energy UCube, 2024.

Figure ES4. Cost curve of undeveloped oil fields, Canada compared to other major global production (shaded areas show interquartile range; black lines show median)



Source: Author's analysis, using data from Rystad Energy UCube, 2024.

U.S. Tariffs on Imports From Canada

In 2025, the United States government has announced, delayed, imposed, and then partially suspended tariffs of 10% on imports of energy from Canada. The policy outlook remains highly uncertain, with possible scenarios ranging from a full U.S. withdrawal of the tariff threat to an escalation of tariffs on both sides. At the same time, it is difficult to predict the effect of tariffs, real or threatened, on complex oil and gas markets. Even if the policy outlook stabilizes, it will be several months before greater clarity emerges. Given these uncertainties, this report does not include the tariffs in its quantitative analysis but rather focuses on market fundamentals. An initial assessment of the market effects of tariffs, however, suggests that, if anything, the findings of this report would be amplified.

The most direct effect of U.S. tariffs on this report's analysis is to make Canadian production less competitive. As such, Canadian production would be more vulnerable to reductions in demand that arise from the global energy transition: a greater proportion will be more costly to produce than the marginal breakeven price. While analysts are divided on how much tariffs would cause Canadian oil and gas investment levels to change, it is clear that any investments that do proceed would face greater economic risks than the absence of tariffs. The projections in this report, therefore, are likely to underestimate the risks of the global energy transition for Canadian production in a context of more restricted trade between Canada and the United States.

Faced with greater economic risks under tariffs, Canadian oil companies and government revenues will remain better off if Canada stops opening new oil and gas fields, and even more so if Canadian governments persuade others to follow suit. In a tariff scenario, the relative economic advantage of stopping new fields could become greater than without tariffs.

Conclusion

For a long time, it has been assumed that Canada's best economic interests lie in the continued expansion of oil and gas production. As global energy markets shift, that assumption may no longer be true. Instead, this analysis suggests a new paradigm whereby the most efficient way to leverage the economic potential of Canada's oil and gas industry is to limit its expansion while using the remaining revenues to accelerate growth in clean industries consistent with a changing global economy.

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Abbreviations and Acronyms

APS	Announced Pledges Scenario
bbl	barrel
boe	barrel of oil equivalent
CCS	carbon capture and storage
CER	Canada Energy Regulator
CTI	Carbon Tracker Initiative
CO_2	carbon dioxide
FID	final investment decision
GDP	gross domestic product
IPCC	Intergovernmental Panel on Climate Change
kbd	thousand barrels per day
kcf	thousand cubic feet
LED	Low Energy Demand scenario
LNG	liquefied natural gas
Mbd	million barrels per day
Mcm/d	million cubic metres per day
$mtCO_2$	million tonnes of carbon dioxide
NPV	net present value
NPV_{10}	net present value at 10% nominal discount rate
NZE	Net Zero Emissions scenario
OPEC	Organisation of Petroleum Exporting Countries
STEPS	Stated Policies Scenario

1.0 Introduction

Oil and gas play a significant role in the Canadian economy, especially in the provinces of Alberta, Saskatchewan, British Columbia, and Newfoundland and Labrador. However, this economic role faces growing challenges as the world moves away from fossil fuels.

1.1 Canada's Oil and Gas Production

Canada is the world's fourth-largest oil producer and fifth-largest gas producer (Energy Institute, 2024). Most of Canada's production is in Alberta, which hosts 83% of the country's oil production and 58% of gas. The remainder of the gas production is mostly in British Columbia, and oil is divided among Saskatchewan, British Columbia, and offshore Newfoundland and Labrador (Figure 1).

Most of Canada's oil and nearly half of its gas is exported, at 81% and 44%, respectively (Canada Energy Regulator [CER], 2024a, 2024b). Of the oil produced in Alberta and Saskatchewan, all but the 15% refined in those two provinces themselves[5] is transported by pipeline, either westward to British Columbia, southward into the U.S. Rockies, or southeast into the U.S. Midwest markets and beyond to the Gulf of Mexico coast. Exported gas serves U.S. markets, primarily the West Coast and the Midwest. The centre of gravity of Canadian gas usage is moving westward as growing U.S. production increasingly serves the Midwest, U.S. East Coast, and even eastern Canada.

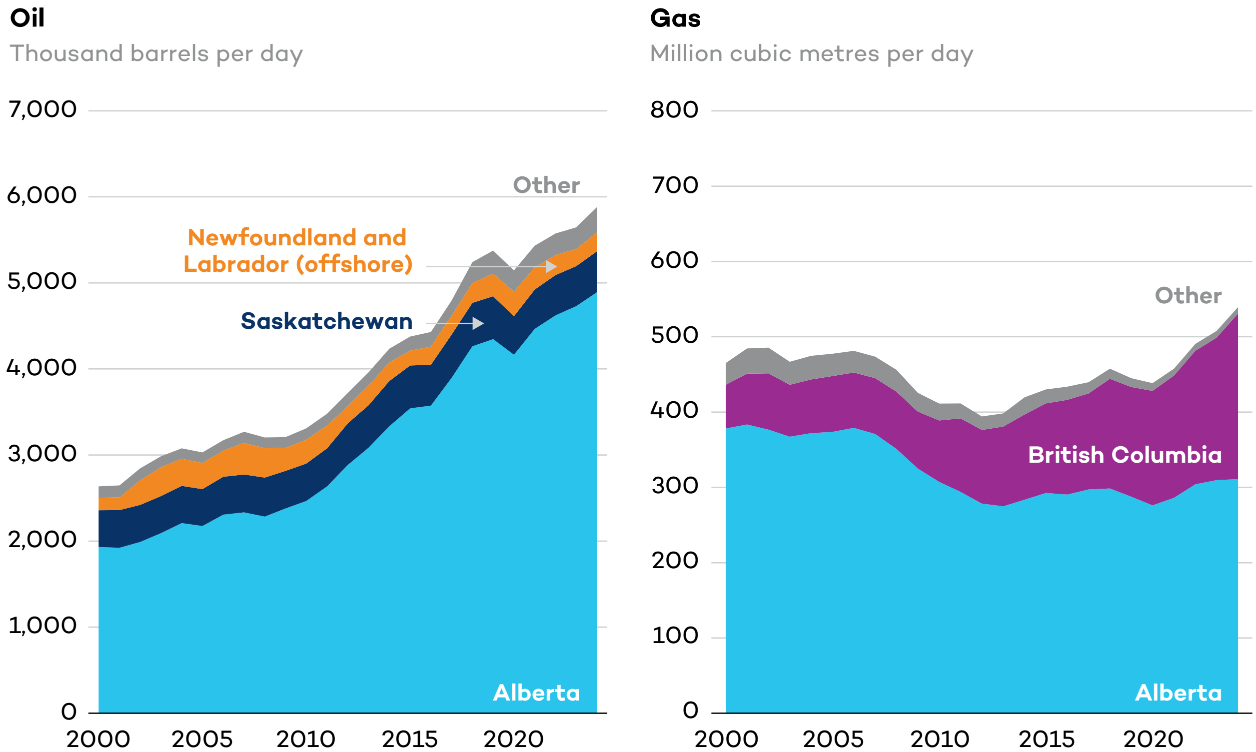
Table 1. Upstream (extraction-related) oil and gas contribution to Canadian and provincial economies, 2023

	Canada	Alberta	Saskatchewan	Newfoundland & Labrador	British Columbia
Oil and gas contribution to GDP	3.0%	16.2%	8.8%	14.4%	1.5%
Oil and gas share of jobs	0.7%	5.4%	1.2%	1.4%	0.2%
Oil and gas contribution to government revenues	0.7%	33%	4%	7%	1%

Data source: Statistics Canada, additional details and sources are outlined in Appendix A.

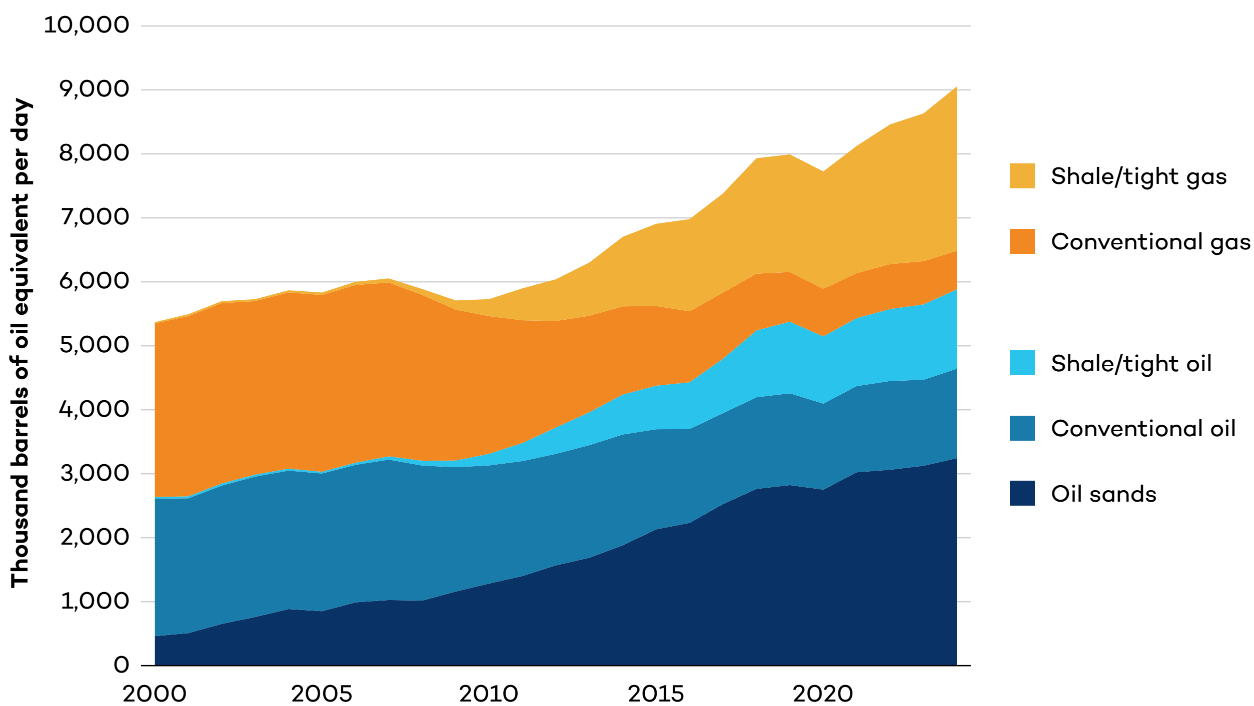
[5] Combined refining capacity is 700 kbd (CER 2021c, 2021d), compared to production of around 4.5 mbd.

Figure 1. Oil and gas production by province, 2000–2024



Data source: Rystad Energy UCube, 2024.

Figure 2. Oil and gas production by type, 2010–2024

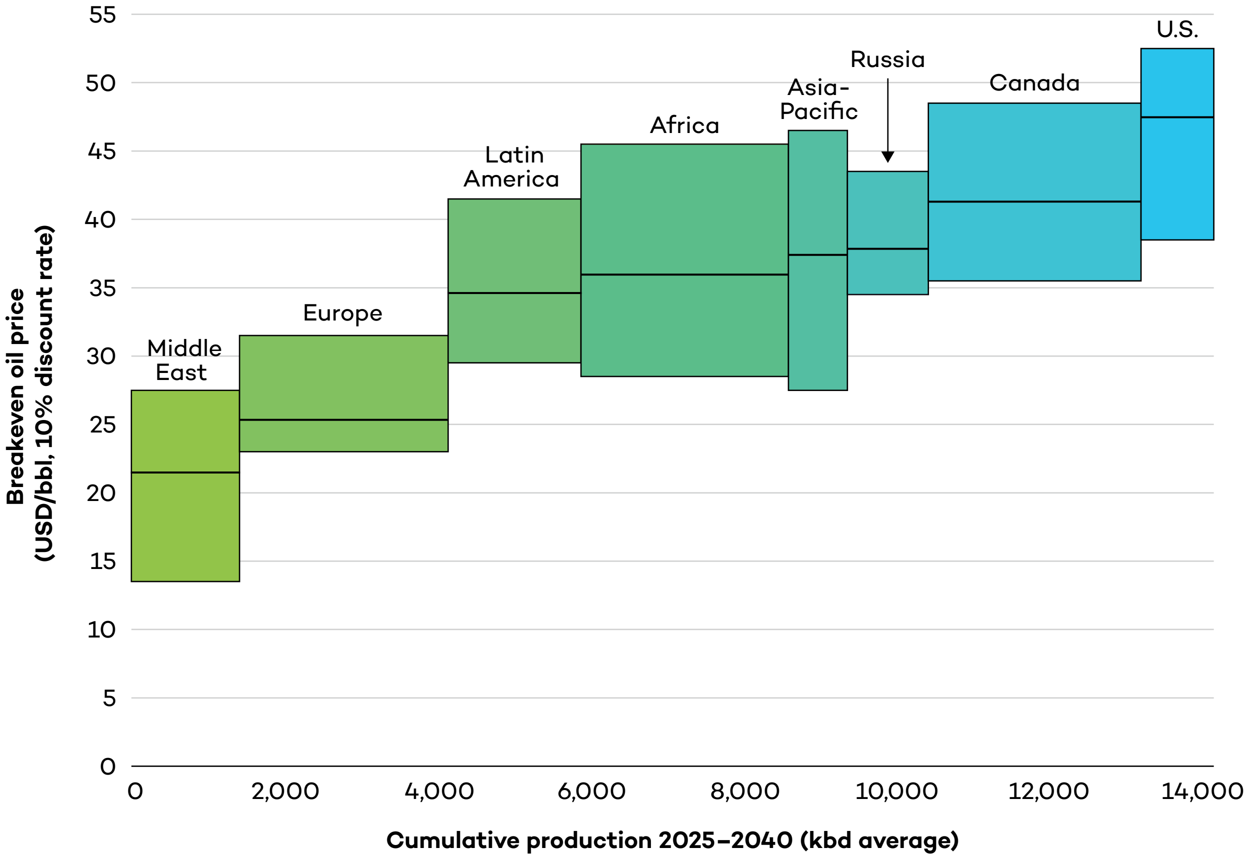


Data source: Rystad Energy UCube, 2024.

While the oil and gas sector is significant in Canada, the Canadian economy is highly diversified compared to many other oil and gas producers (Prince, 2023). For some provinces, however, the sector is more important (Table 1). (Note that the provincial revenue shares in Table 1 include only royalties, not other sources of upstream oil and gas revenue, such as corporate income tax or payments to the provincial revenue funds.)

A large portion of Canadian oil and gas production, and most of its growth, are unconventional. Oil sands account for 56% of oil production; 21% of oil and 81% of gas are produced by hydraulic fracturing (fracking) (Figure 2).

Figure 3. Cost curve of undeveloped oil fields[6]: Canada compared to other major global production (shaded areas show interquartile range; black lines show median)



Source: Author's analysis, using data from Rystad Energy UCube, 2024.

Canada's oil is some of the world's most expensive to produce and transport to market. Figure 3 compares different regions for the totality of costs for new fields, represented by the breakeven

[6] Includes undeveloped conventional fields, undeveloped oil sands projects, and tight oil in new acreages where infrastructure has not yet been built.

price needed to achieve a commercial return (Box 2).[7] While efforts to reduce costs over the last decade have shown some success (Birn, 2019), so have efforts to reduce costs elsewhere in the world, making Canada still expensive compared to other producers. Being high on the cost curve creates greater economic risks relative to lower-cost producers.

Following the opening of the Trans Mountain Pipeline expansion in May 2024, Canada's oil and gas industry is now seeing a surge in capital investment (Potkins, 2024), making this a timely moment to assess the economic outcomes of future production.

1.2 Global Energy Transition

Global oil consumption has grown consistently since the modern oil industry was established in the 1850s. The only years that consumption has declined have been due to the temporary effects of global economic recessions. Gas consumption has also consistently grown, especially since the mid-20th century.

But this era of constant growth is likely coming to an end as the world transitions to an energy system based on renewable energy and electrification. This energy transition is being driven by the rapidly falling costs of renewable generation and batteries. In the largest demand segments for both oil and gas, clean alternatives' shares are growing rapidly and are set to soon drive oil and gas demand into absolute decline.

For example, nearly 40% of oil is consumed in road transport (International Energy Agency [IEA], 2023b). In 2023, 18% of car sales worldwide were electric vehicles (IEA, 2024a). Electric car sales have now overtaken oil-fuelled cars in China (Reuters, 2024), which is the world's largest market and shapes the global car industry due to its low-cost production. As these new vehicles progressively replace the existing vehicle fleet, they will eat into this largest segment of oil demand.

Similarly, power generation accounts for nearly 40% of global gas consumption (IEA, 2023b). Wind and solar generate over 10% of global power (IEA, 2024b), a share that is rising fast as they now provide the cheapest power in countries that together account for over 80% of global electricity generation (BloombergNEF, 2023). The second-largest segment of gas consumption is in buildings, especially for heating. In the United States, there are now more heat pumps installed each year than gas furnaces (IEA, 2023a).

Even in demand segments for which the clean alternatives are not yet cost-competitive, a shifting cost profile means that they are likely to become cheaper within the coming years, driving further disruption of oil and gas demand (Muttitt et al., 2021).

[7] For each region, there is a range of costs among different fields. Canada has the second-highest median breakeven price, meaning that most fields in other regions (except the United States) will be cheaper than most Canadian fields, but some Canadian fields will be cheaper than some fields in other regions.

As a result of these changes in market share, most major forecasters now predict that global oil consumption will peak during the 2020s, even if no new policies are introduced. This is the projection, for example, of the IEA (2024c) and oil companies such as BP (2024) and ExxonMobil (2024). Oil industry consultants Wood Mackenzie's (2024) base case predicts the peak occurring in 2032. The only major forecasters that project continued growth through the 2030s and 2040s are the Organisation of the Petroleum Exporting Countries (OPEC, 2024) and the U.S. Energy Information Administration (2023).

Projections of gas demand in business-as-usual scenarios are more varied (though 1.5°C scenarios with limited carbon capture and storage [CCS] consistently show a decline in gas) (Green et al., 2024). The IEA projects that gas demand will also peak this decade, even with no new policies. Wood Mackenzie sees a gas peak in the late 2030s, while the other forecasters all see continued growth until at least 2050 in the absence of new policies. However, renewable energy generation, dominated by wind and solar, is now growing faster than electricity demand, hence eating into fossil fuels' share (Fyson et al., 2023).

While insufficient to achieve the goals of the Paris Agreement, governments have progressively adopted more climate policies, pushing down expectations of future oil and gas demand. The Climate Action Tracker estimates that current policies in 2024 put the world on track for 2.7°C of warming, compared to 3.4°C estimated in 2017 (Climate Action Tracker, 2017, 2024). The IEA's projection of 2040 oil demand has progressively fallen from 103 mbd based on policies in effect in 2018 to 94 mbd based on today's policies; its 2040 gas projection has fallen from 5,400 to 4,400 bcm over the same period (IEA, 2018, 2024c).

New policies will drive a faster transition than can be expected based on existing policies alone; however, backlash policies will not necessarily slow it. The above forecasts are now driven primarily by technological competition. While past policies have helped enable cost reductions (Grubb et al., 2014; Nemet, 2019), clean energy technologies' cost advantage makes it difficult for anti-environmental policies to slow their penetration compared to these forecasts, despite recent elections (Valdmanis, 2024). In other words, these forecasts likely set a floor for the pace of energy transition, which progressive policy can raise but regressive policy is less able to lower.

1.3 Stranded Assets and Economic Risk

Stranded assets are defined as capital investments that fail to achieve a commercial return on investment due to changes in government policies or market demand compared to what was expected when the investment was made (see, e.g., Caldecott, 2017).

The term "stranded assets" was first applied to climate change and energy transition in a 2011 report by the Carbon Tracker Initiative (CTI). That report observes that a large portion of company valuations is determined by cash flows more than a decade into the future, suggesting that fossil fuel company stocks may constitute a "carbon bubble" that would burst once the impact of the transition is incorporated into valuations. Subsequent Carbon Tracker reports quantify the capital investment that would be stranded. CTI, for example, finds that 62% of investments approved in 2021 and the first quarter of 2022, totalling USD 103 billion, were inconsistent with IEA's 1.7°C Announced Pledges Scenario, including USD 58 billion that was outside even a 2.5°C outcome (Allen & Coffin, 2022).

Several scholarly studies have estimated the cost of asset stranding. For example, Mercure et al. (2018) find a discounted global wealth loss from stranded fossil fuel assets of between USD 1 trillion and USD 4 trillion in a 2°C scenario, a loss comparable to the 2008 financial crisis. Semieniuk et al. (2022) find the upstream oil and gas industry loses USD 1 trillion—USD 100 billion of it in Canada—in a scenario where the European Union and East Asia reach NZE, respectively, in 2050 and 2060, compared to business as usual.

Canada's oil has been a particular focus of assessments of economic viability during the energy transition because of its high production costs. Jaccard et al. (2018) find a less than 5% probability that new oil sands investments would be profitable over the next 3 decades in a world that limits warming to 2°C. Heyes et al. (2018) find that global action on climate change would likely make significant oil sands expansion economically unviable. Dolman (2020) similarly finds that no new oil sands projects would be economically viable in the IEA's Sustainable Development Scenario. Erickson and Lazarus (2020) warn that new Canadian oil and gas projects will struggle to compete with lower-cost suppliers as the energy transition unfolds. Whereas these studies focus on new projects, even existing projects risk the returns on already-invested capital. While not an analysis of stranded assets per se, McGlade and Ekins (2015) relatedly find that in a cost-optimizing integrated assessment model, 75% of Canada's oil remains unburned before 2050.

O'Connor (2024) focuses on the proposed liquefied natural gas (LNG) terminals in British Columbia, finding that they will be at the high end of the cost curve and, as late entrants, will likely come online when the market is glutted before facing a decline in demand. Haig et al. (2024) unpack the precarious business case for the LNG Canada terminal that is currently under construction, finding that its economic viability is counting on high future LNG prices, despite large federal and provincial subsidies.

In contrast, Fellows (2022) challenges the oil sands stranded assets narrative, arguing that oil sands production is, in fact, more resilient than conventional oil to falling global demand and prices. He points out that oil sands projects generally have flat production profiles with long plateaus, whereas production from conventional projects declines over time, requiring new fields to be opened to maintain constant production rates.[8] Thus, if falling global demand leads to companies stopping investment, oil sands production would be expected to continue while conventional production declines.[9]

[8] Tight oil and gas projects do the same on a much-accelerated time frame.

[9] Put differently, meeting the ongoing operating expenditures of existing oil sands projects (with already-sunk capital) will generally cost less than meeting the combined operating and capital expenditures of new conventional fields.

Fellows (2022) is right that the physical production of oil sands will be sustained, but this will come at a cost to already-invested capital. The issue of stranded assets—failing to achieve commercial returns on investments—is related to but distinct from the volume of extraction (Box 1). In fact, stranded assets tend to deliver the worst of both worlds: financial losses for companies, while total volumes of oil exceed what would be consistent with the Paris Agreement goals.

Box 1. Stranded assets and unextractable fossil fuels

The concept of stranded fossil fuel assets is sometimes conflated with that of fossil fuels being left unextracted. These two concepts are nonetheless distinct. Where they overlap is that in a world that achieves the Paris Agreement goals, a significant portion of fossil fuel reserves must be left unextracted (Welsby et al., 2021), and in an economically efficient world, the most expensive resources will be among the first left behind. If uncompetitive resources are developed, the investments will become stranded if demand falls as a result of climate policy or the energy transition.

However, once capital has been sunk, it is in the operator's economic interest to keep producing, as long as each additional barrel can be extracted at a lower marginal operating cost than the price it can be sold for. Therefore, in most cases of stranded assets, production continues while failing to make a commercial return on the capital invested. It is only in the more extreme case where prices fall below marginal operating costs that economic incentives encourage an asset to stop operating.[10]

1.4 Wider Economic Impacts of Stranded Assets

Since a landmark speech by then Bank of England Governor Mark Carney (2015), research and policy interest has grown on the impact of stranded assets on financial stability. Carney warned that transition risks, along with climate physical risks and liability risks, could lead to a rapid change in the valuation of key assets that threatens financial stability. In contrast, these risks would be minimized if the transition to a 2°C world began early and proceeded predictably.

Yet policies are not on course to limit warming to 2°C, let alone the revised 1.5°C target. Companies continue to invest in fossil fuels, with the expectation that governments will continue to fail to align policies with achieving the Paris Agreement goals. Van der Ploeg and Rezai (2020) observe, however, that climate policy-making is uneven and can suddenly accelerate in response to political pressures and climate impacts, resulting in sudden devaluations of fossil fuel assets and financial shocks.

[10] Even then, a company may continue operating while making temporary losses if it expects prices to increase again.

Stranded assets can increase the risk of fossil fuel company borrowers defaulting on their debt, in turn diminishing banks' performance and valuation; in severe cases, even leading to a run on a bank. For asset owners, they can lead to a loss of value in their portfolios (Semieniuk et al., 2021). The impacts can spread through the financial system. Many financial actors invest in the same assets, so a single event or cause can have a systemic effect, and contagion can spread the impact through the many linkages between financial firms. A crisis can be exacerbated as the affected banks and investors simultaneously respond to the event, such as by quickly selling off risky assets or rationing their credit (Daumas, 2023; Roncoroni et al., 2021).

Beyond these impacts on the financial system, stranded assets can also impact the macroeconomy (Network for Greening the Financial System, 2024; Semieniuk et al., 2021). Unproductive investment in stranded assets forgoes an opportunity to grow economic output while resulting losses reduce the available capital to reinvest. Reduced values of financial assets can undermine consumer confidence and thereby reduce consumption spending. Negative impacts on fiscal revenues can increase borrowing costs for governments and diminish governments' capacity to spend. The mismatch of nominal climate ambition with concrete policy can create uncertainty, which, in turn, can delay or misdirect investment. A disorderly transition can create economic volatility (Cosbey et al., 2021).

Modelling these various effects, Mercure et al. (2018) find that asset stranding could reduce Canadian GDP by nearly 2% in 2035 compared to present (business-as-usual) expectations, while importing regions such as the European Union, China, and India, as well as low-cost producers such as OPEC, would see a boost to GDP. They find that Canadian losses can be reduced if the economy transitions away from fossil fuel production.

This report focuses on how Canadian oil and gas investments, related government incomes, and the Canadian financial system may experience sudden shocks during the global energy transition away from oil and gas to the extent that this transition advances more quickly than expected by existing investments and production plans ("transition risk"). The quantitative analysis in this report does not account for potential damage to the wider economy arising from the physical impacts of climate change ("physical risk"). Those physical impacts threaten significantly higher costs than the clean energy transition (Network for Greening the Financial System, 2023). Thus, while this report highlights the economic risks from overinvesting in oil and gas production relative to the pace of the global energy transition, it should not be inferred that the economy would be better without an energy transition at all. Rather, the message is the importance of preparedness, resilience, and effective management of change to simultaneously mitigate transition and physical risks.

1.5 Aim and Structure of this Report

This report considers how Canadian oil and gas production will perform as markets decline. It characterizes the economic impacts in different demand scenarios, the role of new field development within this analysis, and how the economic outcomes would change if no new fields were opened and investments were instead directed elsewhere.

The focus on demand for Canada's oil and gas during the transition contrasts with recent Canadian debates about oil, gas, and climate, which have mostly focused on operational greenhouse gas emissions from the production process, notably during the development of an emissions cap. Unlike with operational emissions, Canadian policy-makers or companies have less influence over the evolution of demand in their export markets. As Mertins-Kirkwood and Hulse (2024) put it in relation to the oil sands, "No political party or government in Canada can save the oil sands from collapse if the rest of the world stops buying Canadian oil" (p. 5).

Previous research has found a high degree of stranded asset risk for Canadian production (see Section 1.3). The present report builds on this research in three ways. First, it updates the analysis in light of more recent projections of future global oil and gas demand (especially following technological progress in wind and solar power and batteries), the availability of new climate-constrained scenarios (Section 2.4), and reduced production costs in Canada, especially in the oil sands. Second, this report evaluates the economic costs of asset stranding for the Canadian economy. Third, it assesses the role of new field developments in the economic analysis, as capital has not yet been invested in these fields, thus offering an opportunity for industry (and government regulators) to change course.

Section 2 of this report describes its methodology, including the scenarios considered. Section 3 assesses the proportion of Canadian oil and gas fields that risk becoming stranded assets and derives equilibrium prices for the supply and demand scenarios. Section 4 examines the economic risks arising from stranded assets, including risks to project investments, companies, and government revenues. Section 5 considers how the economic outcomes change if Canada and/or other countries stop opening new oil and gas fields. Section 6 concludes.

2.0 Methodology

2.1 The Carbon Tracker Stranded Assets Methodology

This report's assessment of stranded asset risk in Section 3 uses the Least Cost Methodology developed over the last decade by the CTI, with some adaptations (Coffin & Prince, 2024; CTI, 2019).

Economic theory tells us that at equilibrium in a competitive market,[11] the price will equal the marginal cost of supply.[12] While oil prices vary widely over time in response to short-term market imbalances, the equilibrium price determines the long-term average based on the fundamentals of supply and demand.

For a given level of demand,[13] the methodology assesses which investments are competitive (i.e., can be produced for less than the marginal cost). Since investments in conventional oil and gas and in oil sands have multi-decadal time horizons, economic risk arises because of mismatches between expectations at the time of investment and how energy markets actually unfold over the period in which those investments are trying to achieve their returns. Specifically, that risk applies to fields with higher costs than the marginal level. The shorter time horizons of hydraulic fracturing (fracking) are addressed below (Section 2.3).

In essence, the methodology compares a business-as-usual level of ongoing investment in supply (i.e., where investors expect sustained oil and gas demand) with various scenarios of evolving demand. There are three steps:

- First, a demand scenario is used to project the total volume that will be consumed over a future period. The scenario makes various assumptions about factors that shape future energy markets, such as demographics, policy, technology, and, importantly, the level of climate policy ambition.

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[11] In the oil market, some actors have significant market power, notably OPEC and OPEC+. These are discussed in Section 2.7.

[12] More precisely, the market price will be the point of intersection of the demand curve and the supply curve. In the standard economic model, the amount that is supplied increases with price (because the costlier projects become viable), while demand decreases with price (because some consumers will consume less if the price is too high). Equilibrium occurs where the two curves meet.

[13] In the present methodology, demand is introduced as a fixed volume (independent of price), taken from a scenario in an energy–economy–climate model, such as the IEA's World Energy Model. This is done to relate the analysis to a specific climate limit (or other set of scenario assumptions) for the sector being considered, in this case oil and gas. In reality, climate goals are met or missed based on the combination of greenhouse gas emissions from all sources, each of which behaves dynamically in response to prices. These dynamic behaviours are simulated within the energy–economy–climate model. By taking a fixed volume rather than modelling demand endogenously, the implicit assumption here is that policies will be adjusted until the scenario's outcome is achieved.

- Second, all oil or gas fields in a given market are arranged in a cost curve, from lowest to highest cost, where the x-axis is the volume of production for the period, and the y-axis is the cost of production, represented by the breakeven oil or gas price (see definition in Box 2).
- Third, assuming that the lowest-cost supply will meet demand, the fields up to the level of cumulative production needed to meet the demand scenario are considered competitive, and those beyond it are non-competitive.

Box 2. Key definitions

Field: A subsurface accumulation of oil and/or gas that is currently being, or is planned to be, economically extracted. Note that the extraction plan determines the extent of a field;[14] hence, a field can be seen as an investment project whose scope is defined by a final investment decision (FID). For oil sands projects, "field" refers to an investment project with a distinct FID. For tight oil and gas extraction by fracking, it refers to an acreage with developed infrastructure.[15]

Discount rate: The rate at which the present value of future cash flows decreases for each year into the future at which they will occur. It reflects the fact that a dollar today is worth more than a dollar in the future, because it can be invested in the meantime and generate a return. Or conversely, a dollar can be borrowed now and repaid later, at the cost of having to pay interest on the loan. The discount rate can thus be thought of as reflecting the cost of capital or the opportunity cost of not investing elsewhere.

Net present value (NPV): The cumulative value of all future cash flows (incomes, capital expenditures, operating expenditures, and tax payments) discounted to the present moment. It thus represents the value of an investment project. It is defined in relation to a particular discount rate; NPV_{10} refers to NPV with a 10% discount rate.

Breakeven oil (or gas) price: The minimum oil (or gas) flat, real-terms price needed for a given field to deliver a positive NPV, taking into account all future positive and negative cash flows. The breakeven price is forward-looking from the point of the assessment: it does not consider past cash flows. It is also defined with respect to a discount rate.

Marginal breakeven price: The breakeven price of the most costly production needed to meet market demand, assuming that demand will be met preferentially by the cheapest available supplies.

14 In contrast, the broader term "reservoir" simply describes a geological accumulation regardless of any plan to extract.

15 This report uses the term "field" throughout for readability because it is more accessible than alternative terms such as "investment project" that might be more accurate for unconventional extraction.

2.2 Interpretation and Limitations of the Stranded Assets Methodology

This method does not provide a full simulation of oil and gas markets. Instead, it simplifies their functioning to gain insights into the relative economics of different fields. In any modelling, there is always a trade-off between complexity (realism) and explanatory power: too much complexity can make it harder to see the factors at play.

The central simplification is to focus on a defined time period, which has three main analytical implications. First, it provides a static assessment of competition over the period, ignoring the dynamic interplay between capital and operating costs.[16] Second, it neglects effects that occur outside the specified time period, including earlier capital investments that drive production during that period or the later effects arising from capital investments made during the period. Third, it compares given supply and demand scenarios over the whole period, neglecting the ways that companies respond to price signals, such as by reducing investment when the price is low (CTI, 2019). Considering these caveats, the method should be seen as spotlighting where risk lies rather than making specific quantitative forecasts.

With respect to the third caveat, actual investment decisions are shaped by oil and gas prices. In a scenario of reduced demand, we can expect the price to fall at first, leading companies to suspend investment plans. However, the market tends to oversteer—that is to say, investment is cut by too much, leading to undersupply—so there may be a temporary return to higher prices.[17] Some companies may interpret such a price recovery as a longer-term improvement and start investing again. During the energy transition, prices are likely to be more volatile, as market actors underestimate or overestimate the changes that are happening. In addition, national oil companies, which produce around half the world's oil and gas (IEA, 2023b), are less responsive to market signals than investor-owned companies. Most likely, not all presently projected investments will go ahead as the transition unfolds, but many will, due to companies misreading market signals. Hence, the analysis gives an instructive picture of how much value can be lost based on market fundamentals when companies keep investing but global demand declines according to the scenarios.

[16] In practice, there are three distinct types of company decisions based on a competitive judgment: the initial decision to build a project, periodic decisions about capital investments within the project such as infill drilling, and the ongoing decisions on whether to continue operating the project once built. A company makes capital investment decisions—the first and second decisions—by considering the likely profitability of the investments, given its expectation of future oil prices, and how that profitability compares with what can be achieved by investing the capital elsewhere. As for the third decision, once capital expenditures have been sunk, a company will be incentivized to keep producing even if suffering a loss (or failing to achieve a commercial return) on the capital investment, as long its cost of producing each extra barrel is less than the price the barrel can be sold for. As long as this condition is met, the operator will increase its profit or reduce its loss by continuing to produce, whereas stopping production would be to fully write off the invested capital.

[17] These dynamics, together with the time lags of responses, are a large part of what makes the oil market cyclical.

Furthermore, the degree of economic risk varies between different fields. There is a danger that an assessment of potential stranded assets effectively reduces a continuous variable to a binary one (what proportion of investment gets stranded), thereby collapsing this variation. This report aims to tackle this danger in Section 4.

Finally, a word of caution on the conclusions to be drawn from this analysis. While it is wise to avoid high-cost projects, it would be a mistake to interpret the message as simply "reduce costs" (to below the marginal cost). The inherent problem is one of too great a supply of oil and gas compared to demand, and the methodology considers this in the context of projects' *relative* cost. If all companies reacted to this analysis by successfully reducing their costs,[18] the same risks would apply to those that remained at the higher end of the curve. Indeed, this is what happened worldwide after the significant drop in oil prices between 2014 and 2016.

2.3 Applying the Methodology

2.3.1 Time Period

This report assesses cumulative consumption and production over the period 2025 to 2040. This choice of time period aims to strike a balance between being long enough to capture more of the economic life of new investments and not going so far into the future as to introduce significant uncertainties.

2.3.2. Discount Rate

The report uses a 10% discount rate (in nominal terms), which is the rate conventionally used in the oil and gas industry (Harden, 2014), including in financial disclosures (Henry, 2015). Companies' hurdle rate—the threshold rate of return[19] on which companies decide whether to go ahead with projects—is thus conventionally 10%, although, in practice, companies vary the rate according to the level of risk of an investment (Thom, 2021).[20]

2.3.3 The Rystad UCube

The assessment of volumes and breakeven prices is made using the Rystad Energy UCube (2024), an economic model produced by the consultancy Rystad Energy, which simulates investment and operating decisions on 65,000 oil and gas fields worldwide based on their geology, costs, and projected rates of return. The UCube base case is also used to generate the investment projections (reflecting industry expectations) that are used in this report.

[18] Or if costs fell for other reasons, such as technological innovation or variations in supply markets (e.g., steel prices).

[19] The internal rate of return of an investment is defined as the discount rate at which NPV is zero. Hence, the breakeven price at 10% may be defined either as the price needed to deliver a positive NPV at a 10% discount rate or equivalently as the price needed to achieve a 10% hurdle rate.

[20] For example, CTI routinely uses a 15% discount rate to reflect the elevated risk of oil and gas projects during the energy transition.

2.3.4 New Versus Existing Fields

Rystad categorizes fields by the stage of their life cycle: producing fields, under-development fields, discovered but undeveloped fields, and undiscovered fields. For the first two categories, capital has already been sunk. The fourth category, undiscovered, is quite speculative, as we do not know what companies will find through their exploration efforts; it is based on best estimates of the geology by Rystad experts.

In recent years, CTI's stranded assets assessments have focused only on *new* fields—the last two categories. The rationale for this is that once fields are developed, they are likely to continue to operate for their full economic life (CTI, 2019). Thus, CTI reports since 2019 have (in step 1 above) assessed the demand only for new fields by deducting the expected production of producing and under-development fields from the total demand.

The present report takes a different approach. While it is true that there are barriers to the closure of existing fields due to "carbon lock-in" (Unruh, 2000), there are still ways in which existing fields can react to the price environment. The FID that begins the development phase is the most important investment decision shaping the direction of the project, but not the only one. For example, during the operation of a field, a company will decide how many additional infill wells it will drill. If the price is low, these capital investments can be avoided, even in producing fields. Another reason for a different approach is that since no new fields are needed in the IEA's NZE scenario (IEA, 2021; Section 2.4), the revised CTI method cannot be used to model markets in this scenario.

This report instead assesses the competitiveness of all fields based on their breakeven price. For existing fields, it uses the breakeven price at the well level; hence, individual wells will proceed only if they are competitive.[21] Thus, all investment decisions, both new wells in existing fields and FIDs to develop new fields, are judged by the same metric.[22]

There is an important caution when interpreting the results. The breakeven price is forward-looking (Box 2), which will lead most existing fields to be judged competitive under this

[21] According to the Rystad Energy UCube (2024), oil production from producing and under-development fields over the 2025–2040 period is 79 mbd on average, whereas production from producing and under-development wells is 45 mbd. Hence, new wells in existing fields account for 34 mbd, a significant portion of the total. Furthermore, a small but non-negligible proportion of existing wells has a high forward-looking breakeven price (in spite of the effect of sunk capital) and as such, may be forced to close by lower prices. The UCube projects 500 kbd of oil production from producing and under-development wells with breakeven price above USD 70/bbl over the period, and a further 500 kbd with breakeven between USD 60 and USD 70, even though some or all of their capital has already been invested. These high-cost wells may be stopped by lower prices.

[22] The rationale here is that price is set at the level that clears the market. A company will proceed with a new field (FID) or new well if the expected price is higher than that field's or well's breakeven price (i.e., if it can deliver a positive NPV). Future price expectations are strongly influenced by present prices. If insufficient supply is available (or expected), this will lead to prices increasing until new fields or wells are sanctioned. If there are too many fields or wells—and hence excess supply—the price will fall such that new fields and wells are not sanctioned, and some existing ones could be forced to close.

methodology, as most of their capital has already been sunk. This does not mean, however, that they generate a commercial return on that capital; rather, it means that we are focusing just on decisions that are yet to be made, where capital can still be redirected elsewhere.

2.3.5 Fracking Investments (Tight Oil and Gas)

A significant portion of Canadian and U.S. oil and gas investments are in the extraction of tight oil and gas. This is oil and gas trapped in rock formations with low permeability, such as shale, through which the oil and gas do not readily flow. Such extraction occurs through hydraulic fracturing (fracking), which fractures the rock by injecting high-pressure water, sand, and chemicals to allow the oil and gas to flow.

Fracking projects have very different economics from conventional oil and gas and from oil sands. Whereas conventional and oil sands projects involve a large investment of capital at the start, each fracked well constitutes a standalone investment. The infrastructure investment to open a new area of tight oil and gas resources—pipelines, roads, storage, processing facilities, etc.—is relatively small compared to the drilling and fracking cost. Hence, in contrast to the multi-decade conventional and oil sands projects governed by a single FID, in fracking, fresh decisions are made on whether to drill each well over time periods of weeks. In addition, because of the impermeability, production from tight oil and gas wells declines rapidly, by around 40%–60% per year (compared to around 4%–5% for a conventional well).

As a consequence of these shorter investment time frames, tight oil and gas extraction are more responsive to market changes than conventional and oil sands projects and, hence, less exposed to stranded asset risks than conventional and oil sands projects with multi-decade investment horizons.

For these reasons, this report categorizes fields into five rather than four categories, treating "developed fracking" oil and gas (i.e., that which is within acreages where the infrastructure has been built) as a separate category. In this report, tight oil in the "discovered" category relates to resources that have been discovered in acreages where the infrastructure has not yet been built. This differs from the Rystad Energy UCube's terminology but is more intuitive.[23]

2.3.6 Oil and Gas Markets

Oil is generally considered to be traded in a single global market, with adjustments to the price according to the quality of the crude and where it is sold, because oil is readily and cheaply transported between countries by tanker ships. While the Canadian oil markets have sometimes been influenced by shortages both of pipeline capacity and refineries capable of processing heavy

[23] The Rystad Energy UCube (2024) categorizes tight resources in acreages where infrastructure has been built as "discovered" and those in acreages without infrastructure as "undiscovered" (even if they are known). Hence, this report's change of terminology transfers the former to its own "developed tight" category and moves the latter from "undiscovered" (Rystad) to "discovered" (this report).

crudes, there are not presently such shortages; hence, the most accurate approach here is to assess Canadian oil within the global market (see Box 3).

Whereas oil is mainly a global commodity, gas has historically been a regional commodity governed by the availability of pipeline infrastructure to transport it. This has partially changed with LNG growth in recent years, which adds a global dimension. The analysis of gas in this report considers two markets: the global LNG market and the North American piped gas market. First, it assesses which global production most competitively meets the LNG projected in demand scenarios,[24] up to a maximum for each country of its existing and under-construction LNG export terminal capacity. Second, the portion of North American gas that is competitive in global LNG markets is added to the total domestic North American gas demand in the given scenario, assuming all domestic demand is met by piped gas. Third, it assesses the relative competitiveness of Canadian, U.S., and Mexican production to meet total North American demand (domestic and exported) under each scenario.

Box 3. Local effects on oil markets

To a good approximation, crude oil can be treated as a fungible commodity traded within a single global market: each element of supply and demand is effectively interchangeable with others, with the interaction mediated by the market. Oil prices vary according to quality and location but are linked to common global prices.

The partial exception to this is inland oil markets, which rely on fixed infrastructure (pipelines) to transport the oil. As long as there is not a shortage of pipeline capacity, any surplus in inland Canadian (Alberta and Saskatchewan) or U.S. Midwest markets, for example, can simply be shipped onward to the major refineries of the Gulf of Mexico coast; conversely, any shortfall can reduce the amount that travels onward. In other words, an equilibrium exists between inland and coastal markets. As an approximation, inland crude, in this case, trades at the coastal price minus the cost of piping it to the coast. These linkages break down if pipeline capacity is insufficient, which leads inland regions to develop their own balances of supply and demand, distinct from the global market.

[24] In reality, the amount of LNG that is traded is not fixed but determined by market dynamics. Specifically, a gas producer will judge where it can make the highest return, comparing local prices, regional prices minus the cost of pipeline transportation, and overseas prices minus liquefaction, shipping, and regasification costs. As such, the markets are linked, within constraints of transportation and conversion. By taking LNG volumes exogenously from scenarios, as with total demand for oil and gas (Section 2.1), those market dynamics are left to the energy–economy–climate model that generates the scenarios.

This report's approach assumes that producers prioritize meeting that LNG demand. This is an approximation but justified by the observation that LNG is the fastest-growing gas market. Global LNG exports grew by 5.3% per year from 2013 to 2023, compared to 1.7% per year growth in total gas consumption (Energy Institute, 2024).

The chemical composition and physical properties of crude oil vary between different sources. The proportion of heavy hydrocarbons in the crude oil and its sulphur content is particularly important. Converting crude oil into useful fuel and non-fuel products involves several distinct chemical processes using specific industrial equipment. Different refineries are thus optimized to process different grades of crude oil according to which equipment they have installed. Heavy and sour (high-sulphur) crudes sell at lower prices than light and sweet (low-sulphur), because only refineries that have invested respectively in coking units and desulphurization units can efficiently process them. Most refineries can accept crude supplies other than those for which they are optimized, but the economics of doing so will be less attractive.[25]

The trapped surplus can drive down inland prices if there is insufficient pipeline capacity to the coast. A shortage of connected refineries able to process heavy or sour oil drives down heavy, sour oil prices. These combined effects manifest in the price differential at which the Western Canada Select crude benchmark (heavy, sour, priced at Hardisty, Alberta) trades relative to light, sweet crudes at the coast.[26] The differential blew out several times during the 2010s, as Canadian production grew beyond the capacity of pipelines to export it. The differential peaked in autumn 2018 at USD 50, as pipeline constraints were combined with several U.S. refinery outages for maintenance.

However, as of late 2024, there are unlikely to be pipeline or refinery constraints in the near term, as the opening of the Trans Mountain Pipeline expansion in May 2024 has created surplus transport capacity, and the 2010s saw expansions of coking capacity in Gulf Coast refineries, notably the Motiva refinery at Port Arthur (American Fuel & Petrochemical Manufacturers, 2023), while competing sources of heavy crude from Mexico and South America have continued to decline (Birn et al., 2018). The author's expectation is, therefore, that the demand-driven price reductions in the scenarios will stall Canadian production growth before it gets large enough to run into the pipeline or refinery constraints. For this reason, this report focuses on the global oil market and does not adjust for local market effects.

[25] For example, a refinery without a coking unit that processes heavy crude will be left with a greater proportion of unsellable residues. A coker-equipped refinery can process light crude but at greater purchase cost than heavy crude, thus ceding the advantage conferred by the coker investment.

[26] Western Canada Select has usually been compared to West Texas Intermediate, which for historical reasons is the dominant benchmark in North America. However, West Texas Intermediate is priced at Cushing, Oklahoma, an inland location, and this has diverged from trends in global prices at times (e.g., during the mid-2010s) when pipeline capacity from Cushing to the coast was constrained. A better comparison might be a coastal benchmark, such as Louisiana Light Sweet.

2.4 Demand Scenarios

This report examines the future economics of Canadian oil and gas production. Since we do not know how oil and gas markets will evolve, the report uses scenarios that describe possible futures. The analysis is based on the three main scenarios produced by the IEA (2024c):

- **The Stated Policies scenario (STEPS)** assumes that the policy environment is frozen as it currently stands: no new policies are introduced beyond those already announced. In this scenario, the energy transition proceeds slowly, consistent with warming of 2.4°C above pre-industrial levels.
- In the **Announced Pledges scenario (APS)**, governments that have committed to achieving NZE by mid-century successfully achieve those commitments. This leads to a moderate-paced transition consistent with warming of 1.7°C.
- In the **NZE scenario**, governments succeed in limiting warming to 1.5°C, consistent with the goals of the Paris Agreement, while also achieving the other energy-related Sustainable Development Goals, including universal energy access by 2030 and reducing deaths and illnesses from air pollution. This leads to a fast transition. The IEA does not publish regional data for the NZE scenario; for the gas analysis, this report, therefore, assumes that North America's share of global consumption is the same in the NZE as in the APS.

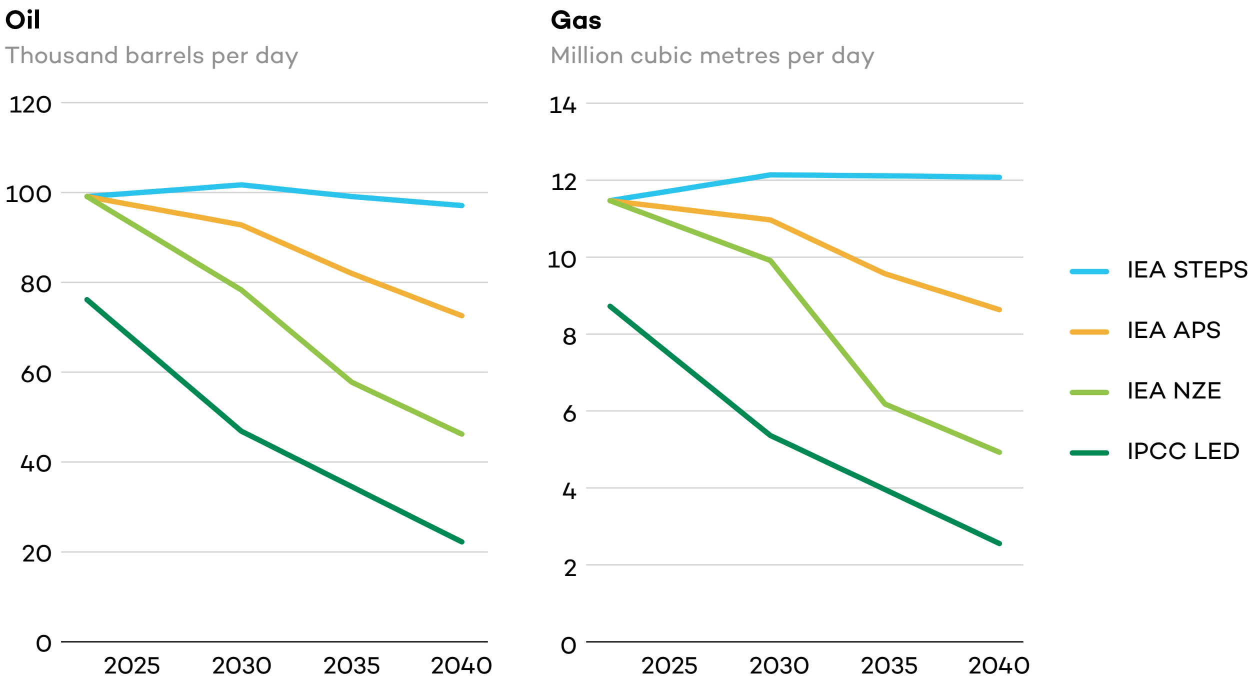
To be consistent with the demand levels as defined by the IEA (2024c, Table 3.1), this report defines "oil" as comprising the Rystad Energy UCube categories of crude oil, condensate, natural gas liquids, and refinery gains.

A fourth scenario is considered as a sensitivity analysis: the **Low Energy Demand (LED) scenario**, which is one of the illustrative mitigation pathways from the Intergovernmental Panel on Climate Change's (IPCC's) *Sixth Assessment Report* (Grubler et al., 2018; IPCC, 2022). Like the NZE scenario, this one leads to warming of 1.5°C. An important difference is that in the LED scenario, there is no reliance on the future availability of CCS; instead, the primary mechanism for limiting emissions is through using less energy while still improving human well-being.

The reason for this sensitivity analysis is that the future of CCS is highly uncertain. Despite three decades of expectations (Wang et al., 2021), so far, only 50 $MtCO_2$ of CCS capacity has been built, with a similar amount presently under construction (Global CCS Institute, 2024). Even when this is completed, the facilities will be capable of capturing and storing at most just 0.25% of annual global CO_2 emissions.[27] CCS remains more expensive than other means to reduce emissions, with major questions about how it will be delivered, incentivized, and funded (Budinis et al., 2018). The NZE scenario relies on 1,000 $MtCO_2$ of CCS by 2030 and nearly 6,000 $MtCO_2$ by 2050 (IEA, 2024c). The LED scenario shows how much faster global fossil fuel consumption would need to decline to achieve the Paris Agreement goals if the IEA's CCS deployment assumptions prove to be too optimistic.

[27] More than half of this capacity is deployed in enhanced oil recovery, where the purpose of injecting CO_2 into the subsurface is to increase reservoir pressures and hence oil production, rather than to store CO_2 over the long term. Hence in these cases, the design, management, and subsequent monitoring are not geared to long-term storage.

Figure 4. Global consumption of (a) oil and (b) gas in four scenarios



Data source: Byers et al., 2022; IEA, 2024c.

For the gas analysis, the share of global gas consumption that is traded as LNG in the LED scenario is assumed to be the same as in the NZE scenario, and the share consumed in North America is the same as in the APS scenario.

None of these scenarios is a prediction. And while they do have different normative claims—in that NZE achieves the Paris Agreement and Sustainable Development Goals, which are clearly desirable—here, the scenarios are used together to represent a range of possible futures that allows us to assess risk. Whereas it is implausible that the policy environment will remain frozen, STEPS provides an important reference case in mapping the domain of possible futures.

2.5 Assessing Economic Impact

Section 4 of this report assesses the economic impacts resulting from stranded assets on oil and gas projects, oil companies and their investors, and government revenues. These assessments assume constant oil and gas prices (in real terms), equal to the marginal breakeven prices determined by the stranded assets assessment of Section 3, using the three IEA scenarios' demand levels. As discussed above (Sections 2.1 and 2.2), actual prices vary over time in response to short-term market imbalances; however, over the longer term, a good estimate of average price is determined by the fundamentals of supply and demand. For comparison, the assessments are also conducted using Rystad Energy UCube's base case price forecasts as a proxy for industry expectations. These vary over the 2025–2040 period, averaging USD 87/bbl for oil and USD 4.60/kcf for gas.

The project assessment calculates the NPV_{10} (NPV at 10% nominal discount rate) of future oil and gas production in different scenarios, modelled in the Rystad UCube. First, the economic effect is illustrated for four projects with typical breakeven prices: one oil sands mine expansion, two in situ oil sands projects, and one offshore conventional field. These illustrations use modelled cash flows from the Rystad Energy UCube discounted back to the year of the FID. Second, NPV_{10} is assessed for all fields as a measure of the value of future oil and gas activities as a whole. A fuller picture of investment value would also consider the risks—market, political, delivery, etc.—but NPV_{10} gives a good indicator, especially for comparative purposes within similar circumstances across Canadian production.

This report also uses NPV_{10} as a proxy for company valuation. Companies are valued using multiple metrics, including the physical value of assets, trust in management quality, and market sentiment, but NPV provides the most important basis because it indicates the expected future economic performance (Johnston & Johnston 2006; Misamore 2017). The NPV of all future Canadian oil and gas operations thus indicates the value of the industry as a whole. In addition to the whole industry's operations, NPV_{10} is also assessed for operations by the four largest Canadian oil and gas companies: Cenovus Energy Inc., Imperial Oil Inc., Suncor Energy Inc., and Canadian Natural Resources Ltd. The report then looks at the degree of exposure of the Canadian financial system to the oil industry to indicate the extent of wider financial risk.

Finally, the impact on government revenues over the period 2025 to 2040 is assessed, in aggregate, from all projects. Again, this is done using the Rystad Energy UCube, which models projects' cash flows, with government revenue based on the detailed federal and provincial fiscal terms. The UCube output does not differentiate federal versus provincial revenues.

For these assessments, it is assumed that fracking projects respond to the price environment, but conventional and oil sands projects do not, as in the latter case, companies are assumed to misread the market signals and believe demand will continue in line with their expectations (Sections 2.2 and 2.3).[28]

Section 5 considers how these economic impacts would change in response to two possible policy interventions by the Canadian and/or provincial governments. It uses the same methodology as above, first assessing the equilibrium oil and gas prices and then the resulting economic outcomes at those prices.

In the first intervention, governments prevent the development of any new fields beyond those already producing or under development. Specifically, it applies to new conventional fields, new oil sands investment projects (including phases), and new tight oil and gas acreages that do not

[28] For fracking projects, this is represented in the UCube by disregarding (excluding) uncommercial projects—that is to say, projects go ahead only if judged commercial in the price environment (where it is known what future prices will be). For conventional and oil sands, uncommercial projects are not disregarded, which is to say, they proceed even if the price is too low for them to be commercially viable (as it is assumed that companies misjudge what future demand and prices will be) (Rystad Energy, 2024).

yet have infrastructure. This policy could be applied, for example, through the development consent process.

In the second intervention, Canadian governments apply international diplomacy to persuade other governments to stop the development of new fields in their territories, too. This report assesses a scenario where this diplomacy achieves a 10% success rate (i.e., stopping 10% of the production from new fields coming online) spread evenly across the cost curve.

2.6 U.S. Tariffs on Imports from Canada

During 2025, tariffs on Canadian oil and gas exports to the United States have fluctuated between being threatened, imposed, and partially suspended. The policy outlook remains highly uncertain, with possible scenarios ranging from a full U.S. withdrawal of the tariff threat to an escalation of tariffs on both sides. When tariffs were first imposed in March 2025, the Canadian Association of Petroleum Producers (2025) rightly noted that it would be hard to predict how complex oil and gas markets would change as a result. Thus, even if the policy outlook stabilizes, it will be months before greater clarity emerges.

All else being equal, tariffs reduce profitability for Canada's oil and gas producers, squeeze margins for U.S. refiners, and push up fuel costs for U.S. consumers, with the balance of these three effects varying from place to place, according to each player's ability to access alternative sellers and buyers (Esau, 2025; Varcoe, 2025). In much of the inland market of the U.S. Midwest, there are few alternative options to Canadian supply, so more of the impact will likely be felt by consumers.

Trade flows could shift as Canadian producers seek more non-U.S. markets while more U.S. crude stays at home; however, the potential extent of such changes is constrained by available pipeline infrastructure. In the longer term, there may be incentives to adapt infrastructure, such as reversing pipelines in the U.S. to flow south-to-north rather than north-to-south. That said, the construction of new, large-scale pipelines is unlikely to be economically attractive, as evidenced by the repeated cost overruns on the Trans Mountain Pipeline expansion and its inability to cover those costs from transit fees, relying instead on subsidies by Canadian taxpayers (Gunton, 2024).

Given these uncertainties, this report does not include the tariffs in its quantitative analysis but rather focuses on market fundamentals. The effect of U.S. tariffs on the report's headline findings is assessed at the end of each of the following sections.

2.7 A Note on OPEC and the Oil Market

Since this report relies on an assessment of equilibrium oil and gas prices, an obvious question is how OPEC may influence prices. Historically, OPEC has had less market power than is commonly believed, in two respects. First, a trade-off exists between higher prices and OPEC's market share. This limits OPEC's capacity to boost prices by restraining production because doing so will enable higher-cost sources of oil to enter the market, reducing OPEC's market share and weakening its market power over the longer term. This is what happened with the North Sea during the high prices of 1973 to 1985 and with fracking from 2008 to 2014; in both cases, OPEC eventually had to give up efforts to shore up prices, as the weight of the market was shifting too far (Fattouh et al., 2015).

Second, OPEC has often struggled to maintain discipline, with its members cheating on their quotas most of the time (Colgan, 2014; The Economist, 2024). As the only member with significant spare capacity, Saudi Arabia has historically made most of the changes to production, along with smaller contributions from its allies, Kuwait and the United Arab Emirates, while other members have tended to produce as much as they can, essentially free-riding on Saudi restraint.

More recently, since OPEC entered an agreement in 2016 with several non-members, the informal OPEC+ grouping has been relatively successful at operating collectively. OPEC+ accounts for about 60% of global oil production, compared to OPEC's roughly 40%. The advantages of a greater market share appear to have outweighed the difficulties of reaching an agreement among a larger and more diverse group of countries. Meanwhile, OPEC has improved its internal discipline and become much more effective at adjusting production in response to short-term changes in the market (Fattouh & Economou, 2024). However, most OPEC+ members face constraints in their ability to meaningfully increase their long-term production. Saudi Arabia remains the only country able to significantly boost production in pursuit of greater market share (Fattouh & Economou, 2025).

Two specific questions that arise for this report are: Will OPEC cut production to shore up prices in response to demand-driven price reductions, thereby reducing the price risk for Canadian production? And if Canada or others restrict new field development, will OPEC increase production, reducing prices and thereby cancelling any positive effects on Canadian production?

The answer to the first question is likely negative. OPEC has generally struggled to influence the market in times of downward pressure on prices because lower prices incentivize OPEC members to cheat on their quotas to sustain their income, creating a positive feedback loop. Furthermore, the experience of the high prices of the 1970s and early 1980s—and to a lesser extent, those of 2008 to 2014—demonstrate that fighting a long-term shift in market trends can only come at the expense of losing market share. If global oil demand enters long-term decline, OPEC and OPEC+ will ultimately have to accept that and the lower prices it entails.

The answer to the second question primarily relates to Saudi Arabia. In recent years, Saudi Arabia has shown a preference for higher prices than previously, due to its greater fiscal needs, not least to finance the Vision 2030 economic transformation (Smith & Abu Omar 2024). Whether OPEC increases production in response to reduced Canadian (or other) supply would depend on a calculation—primarily by Saudi Arabia—as to whether the loss due to the resulting lower prices would outweigh the gain from an increase in volume and on expectations of future oil demand. This is assessed in Box 4 in Section 5.

3.0 Stranded Assets and Equilibrium Price Assessment

This section combines available supply with demand scenarios to assess the equilibrium oil and gas prices. The assessment also reveals what portion of projected Canadian base-case production and investment are uncompetitive (with a higher breakeven than the equilibrium price) and, hence, at risk of becoming stranded assets if the investments go ahead, first for oil and second for gas.

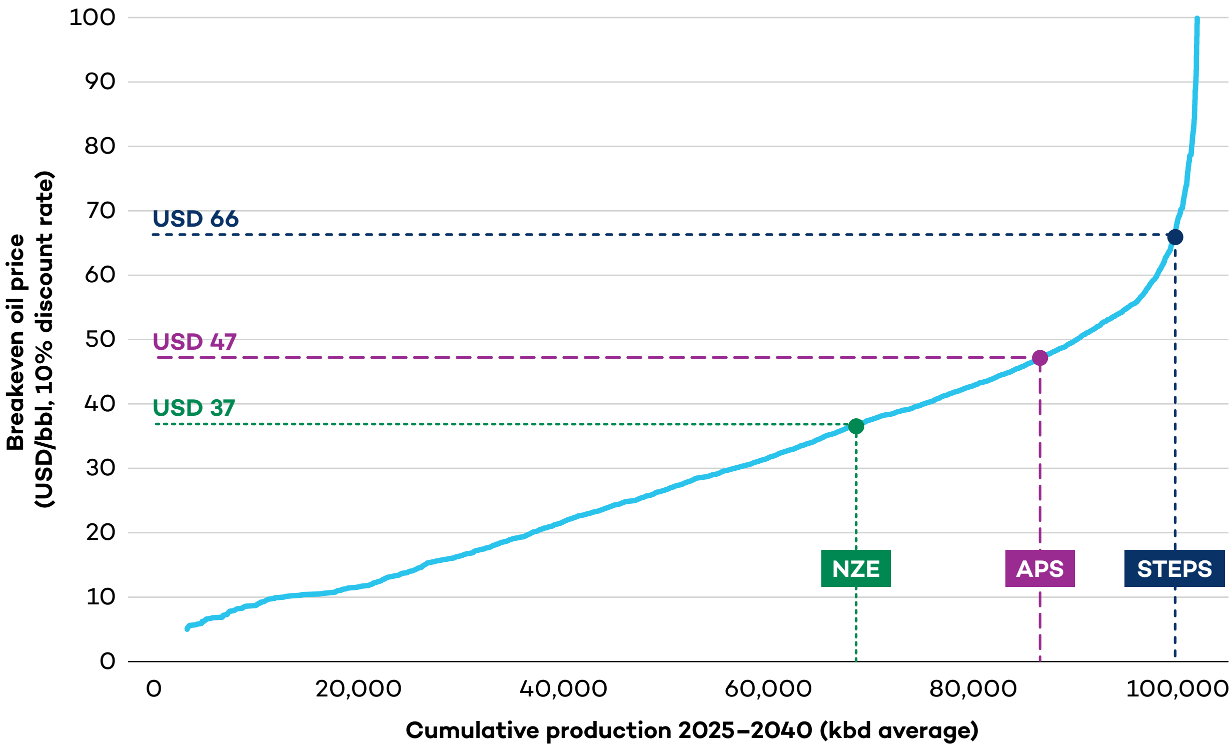
3.1 Oil Production

Figure 5 shows the cost curve of global oil production (including both existing and new fields) for the period 2025 to 2040, based on forward-looking breakeven price at 10% nominal discount rate. This simplified version of Figure 3 shows the cumulative volume that may be extracted over the period at a given breakeven price, modelled using the Rystad Energy UCube.

Superimposed on this are the cumulative consumption figures over the same period in the three IEA scenarios: 99,700 kbd (average) in STEPS, 86,500 kbd in APS, and 68,700 kbd in NZE. These, in turn, tell us the marginal breakeven oil prices based on market fundamentals: USD 67 per barrel at the STEPS demand level, USD 46 at APS demand, and USD 37 at NZE demand.

Canada's fields are shown in a cost curve in Figure 6. The marginal breakeven prices derived above from the global cost curve are used to assess how much of Canada's production is competitive in each demand scenario: any fields to the left of the red vertical dashed lines. If uncompetitive fields are developed, they will fail to achieve commercial returns in these demand scenarios—that is, they will become stranded assets. The proportion of projected production in the UCube base case that comes from these uncompetitive fields is then shown in Table 2: attention should be focused especially on the fields that have not yet been developed, where decisions are yet to be made. The competitiveness assessment is only a forward-looking one: producing and under-development fields may still deliver uncommercial returns on already-invested capital, in spite of lower proportions indicated to be uncompetitive in Table 2. To repeat the caveat noted in Section 2.3, the breakeven price is a forward-looking measure, reflecting only future cash flows. Thus, the finding that 1% of producing fields are uncompetitive in STEPS means that in those 1% of fields, *future* capital investments would fail to achieve commercial returns. Some of the remaining 99% would also fail to achieve commercial returns on the capital that has already been invested.

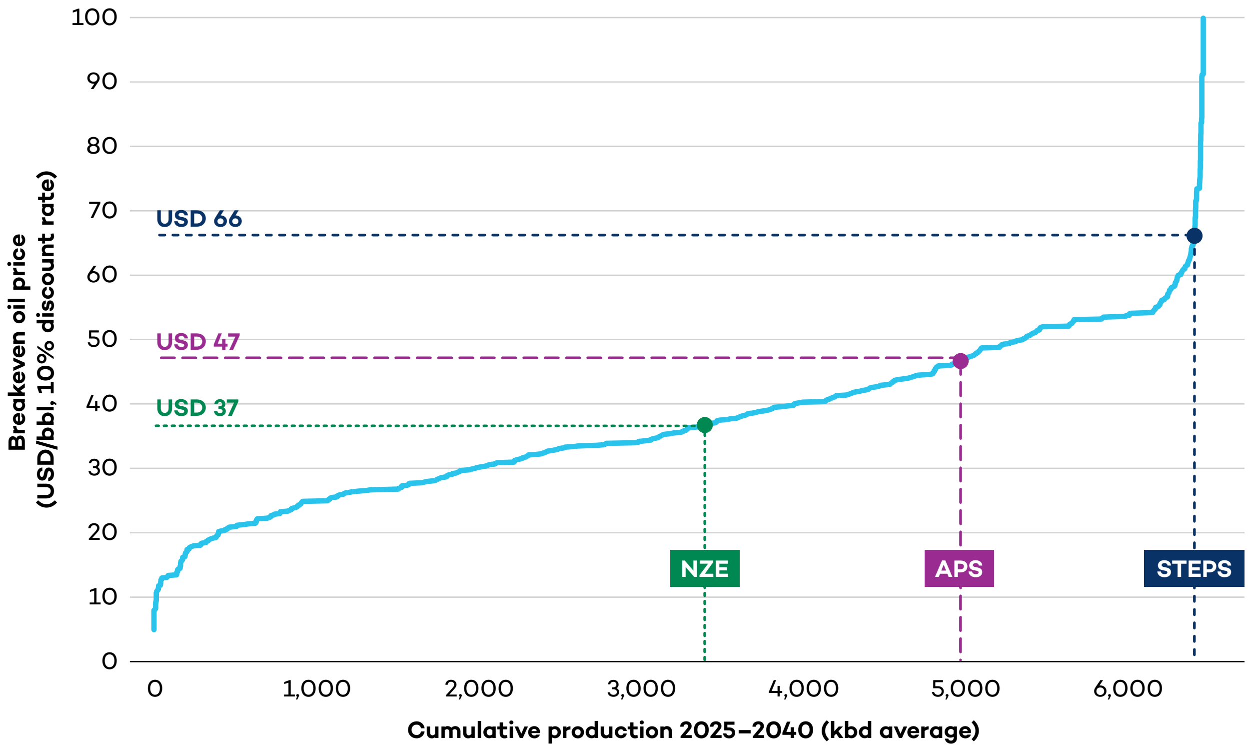
Figure 5. Cost curve of global oil production, showing equilibrium price for three IEA demand scenarios



Source: Author's analysis, using data from Rystad Energy UCube, 2024.

While a small amount of Canadian production is uncompetitive with STEPS demand, significant shares of projected production are uncompetitive with either APS or NZE demand levels. Indeed, as can be seen from Figures 5 and 6, Canadian oil production is particularly vulnerable to the effects of the energy transition: with APS and NZE demand, larger proportions of Canadian production are uncompetitive compared to global production. This is because Canadian oil costs more to produce (Section 1.1).

Figure 6. Cost curve of Canadian oil production, showing equilibrium price for three IEA demand scenarios



Source: Author's analysis, using data from Rystad Energy UCube, 2024.

Table 2. The proportion of projected base-case Canadian oil production in which new investment is uncompetitive (at a 10% discount rate) in different demand scenarios

	Producing	Under development	Fracking developed	Discovered, undeveloped	Undiscovered	Total
STEPS	1%	0%	1%	2%	3%	1%
APS	23%	3%	26%	32%	23%	23%
NZE	40%	31%	63%	74%	65%	49%

Note: This table does not assess the competitiveness of investments already made.
Source: Author's analysis, using Rystad Energy UCube, 2024.

3.2 Gas Production

The analysis is now repeated for gas. In this case, two markets are considered: North American consumption served by pipelines and global consumption served by LNG. The first step is to assess how competitive North American gas production is in the global LNG market in each demand scenario. This is then added to the projected North American consumption, as shown in Table 3.

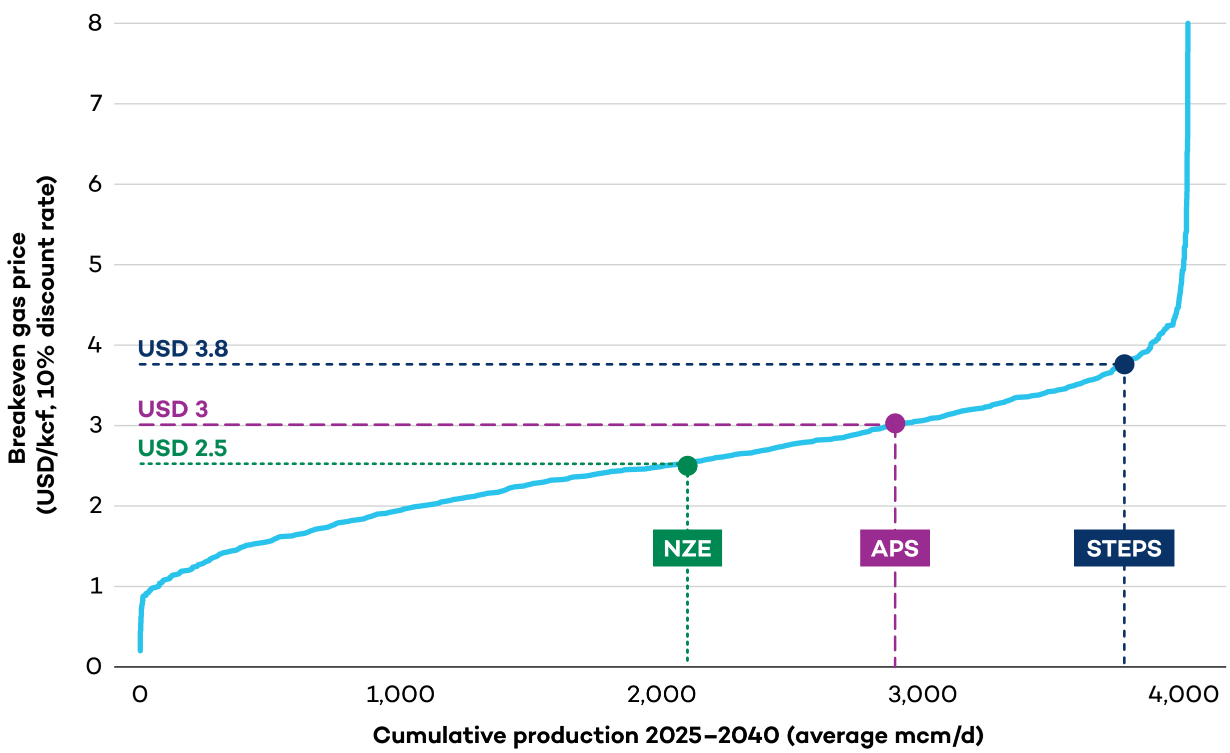
Table 3. The volume of demand for North American gas (mcm/d) in different scenarios, 2025–2040

	North American consumption	LNG exports	Total demand
STEPS	2,926	767	3,694
APS	2,262	585	2,847
NZE	1,843	265	2,108

Source: Author's analysis, using data from Rystad Energy UCube, 2024.

Figure 7 shows the cost curve for North American gas production. The above total volumes of consumption are superimposed, and the breakeven gas prices are inferred: USD 3.8/kcf with STEPS demand, USD 3/kcf with APS, and USD 2.5/kcf with NZE demand.

Figure 7. Cost curve of North American gas production showing the equilibrium price for three IEA demand scenarios



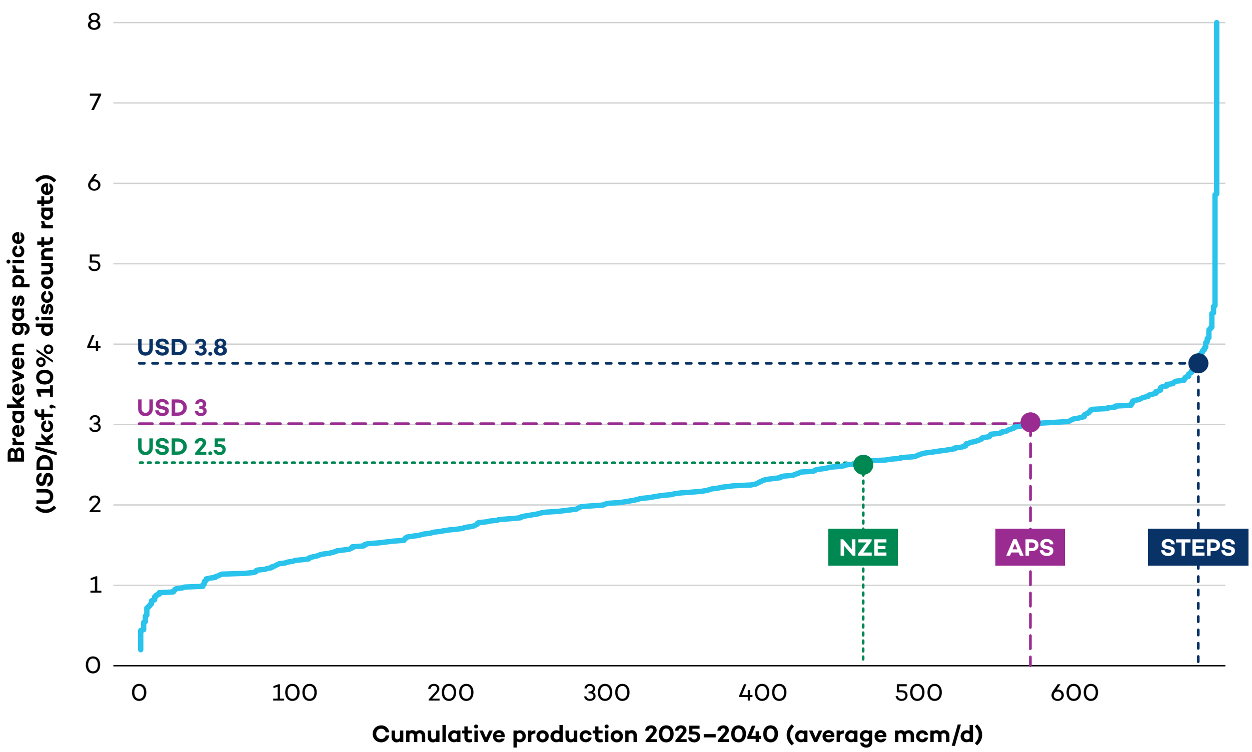
Source: Author's analysis, using data from Rystad Energy UCube, 2024.

Figure 8 shows the cost curve for Canadian gas fields, with the above marginal breakeven prices marked, to reveal how much Canadian gas production is competitive in each scenario. The proportion of production in which new investment is uncompetitive (setting aside investments already made) is then shown in Table 4.

In contrast to the situation with oil, less Canadian gas production is uncompetitive—relative to North American gas production as a whole—because Canadian gas has a cost advantage over U.S. gas. However, since the cost advantage is small, it may be offset by greater transportation costs to the main demand centres; hence, the picture might be somewhat less positive than the analysis here, which treats North America as a single, connected market.[29] Canadian gas could also be disadvantaged if the United States were to apply tariffs on gas imports.

In any case, a significant proportion of projected base-case gas production is uncompetitive at the APS and NZE demand levels.

Figure 8. The proportion of projected base-case Canadian gas production that is uncompetitive (at a 10% discount rate) in different demand scenarios



Source: Author's analysis, using data from Rystad Energy UCube, 2024.

[29] Note that this does not mean that molecules of gas extracted in Canada can be freely transported to be consumed anywhere on the continent (or indeed exported from LNG terminals): rather, Canadian gas may supply the more proximate markets, such as the U.S. Midwest, freeing up U.S-extracted gas to be transported elsewhere.

Table 4. The proportion of Canadian gas production in which new investment is uncompetitive (at a 10% discount rate) in different scenarios

	Producing	Under development	Fracking developed	Discovered, undeveloped	Undiscovered	Total
STEPS	1%	0%	1%	5%	23%	1%
APS	6%	1%	23%	24%	49%	6%
NZE	13%	8%	40%	50%	50%	13%

Note: This table does not assess the competitiveness of investments already made.
Source: Author's analysis, using Rystad Energy UCube, 2024.

3.3 Stranded Assets as a Proportion of Invested Capital

To put the foregoing analysis in context, Table 5 shows how much of the projected capital expenditure over 2025 to 2040 potentially becomes stranded at the three scenarios' demand levels.

Table 5. The proportion of projected base-case capital expenditure over 2025–2040 that is invested in uncompetitive projects in different demand scenarios

	Producing	Under development	Fracking developed	Discovered, undeveloped	Undiscovered	Total
STEPS	6%	0%	2%	6%	6%	5%
APS	37%	11%	38%	42%	40%	39%
NZE	56%	48%	67%	74%	73%	66%

Note: This table does not assess the competitiveness of capital already invested.
Source: Author's analysis, using data from Rystad Energy UCube, 2024.

Out of USD 669 billion in capital expected to be invested over the period 2025 to 2040, USD 260 billion (39%) will be uncompetitive with APS demand and USD 445 billion (66%) will be uncompetitive with NZE demand. The share of capital at risk is greater than the share of production, largely because the fields needing major capital investment are the ones that are most affected by lower oil prices.

3.4 The LED Scenario

To examine the impact of assumptions concerning CCS, the analysis is now also applied to the LED scenario, which does not rely at all on CCS, as a sensitivity case. Results, displayed in Table 6, show that, to follow this pathway, the vast majority of fossil fuel production and consumption facilities would need to be shut down very rapidly. It also illustrates the significant reliance on CCS in the IEA demand scenarios. If CCS cannot be delivered at that scale and pace, and if governments nonetheless pursue the same climate goals by other means, almost no oil and gas production would be economically viable.

Table 6. The proportion of production in which new investment is uncompetitive at LED demand (2025–2040, 10% discount rate)

	Producing	Under development	Fracking developed	Discovered, undeveloped	Undiscovered	Total
Oil production	82%	83%	92%	98%	97%	87%
Gas production	24%	33%	61%	78%	52%	52%
Capital investment (oil & gas)	94%	81%	85%	95%	99%	93%

Note: This table does not assess the competitiveness of investments already made.
Source: Author's analysis, using data from Rystad Energy UCube, 2024.

3.5 The Effect of U.S. Tariffs

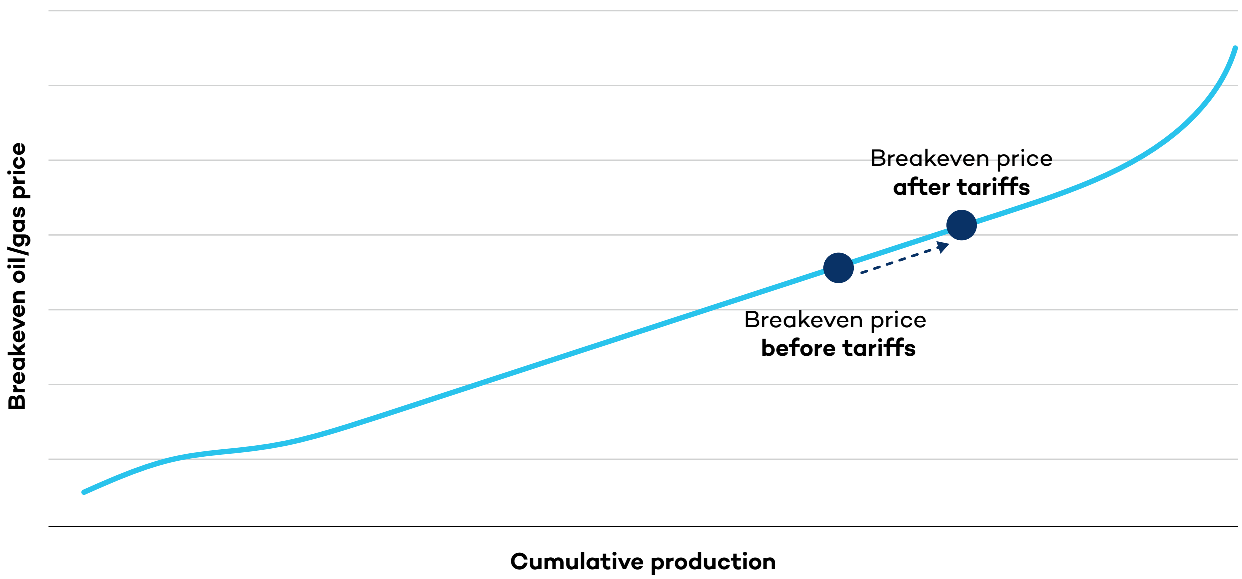
The most direct effect of U.S. tariffs on this report's analysis is, all else being equal, to make Canadian production less competitive in the U.S. market, and less competitive in general, given its limited access to other markets. Effectively, then, U.S. tariffs would push Canadian production rightward in the cost curves shown in Figures 5 and 7—that is, Canadian production would have a higher breakeven price—as illustrated for an individual field in Figure 9.

As such, Canadian production would be more vulnerable to reductions in demand that arise from the energy transition: a greater proportion will be more costly to produce than the marginal breakeven price. In other words, tariffs would cause some Canadian fields to move from being within threshold demand levels to being outside of them. Hence, in a scenario of sustained U.S. tariffs, the proportions of Canadian production that are uncompetitive will be greater than those stated in Tables 2, 4, 5, and 6.

Tariffs would also increase the threshold oil and gas prices for given demand levels because more costly fields would be needed to replace tariff-hit Canadian ones. This price rise would not fully offset Canadian losses because it is primarily at the expense of Canadian (and Mexican) production that the market balance would shift.

At the same time, U.S. tariffs—or the threat thereof—may lead some oil and/or gas companies to withhold investments they would have made otherwise and, hence, not incur the downside economic risks associated with new oil and gas production during the energy transition. Analysts are divided on how much Canadian oil and gas investment levels will change as a result of tariffs (Stephenson, 2025). However, any investments that do proceed will clearly face greater risks in the presence than in the absence of tariffs (i.e., greater risks than estimated in this report).

Figure 9. Illustrative effect of U.S. tariffs on a Canadian oil or gas field, within Figure 5 or 7 (showing global oil production or North American gas production)



Source: Author.

4.0 Economic Impacts of Stranded Assets

The previous section has identified the extent of stranded oil and gas assets in different scenarios as a proportion of projected production and capital expenditure. This section assesses the combined economic impacts of those stranded assets for both oil and gas.

This section looks first at the impact on project investments, then at the impact on companies and (by extension) the financial system, and finally at the impact on federal and provincial government revenues. These impacts are assessed using the (flat, in real terms) equilibrium prices calculated in Section 3. These are compared to outcomes under the Rystad Energy UCube base case price forecasts as a proxy for industry expectations.

4.1 Impacts on Illustrative Projects

To begin, the impact of lower prices resulting from the energy transition is presented for illustrative purposes in four projects, with breakeven prices (at a 10% discount rate) typical of Canadian projects:

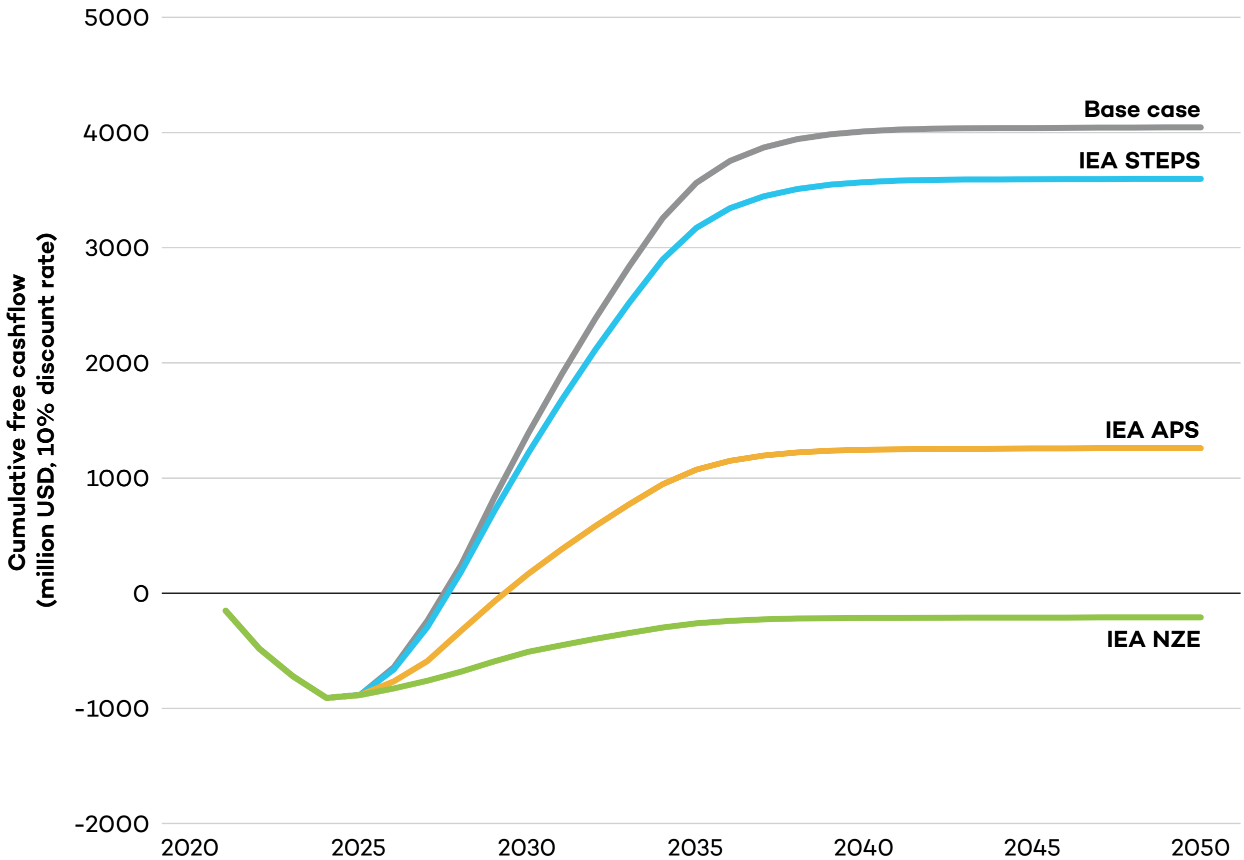
- **Syncrude Mildred Lake Extension West**: A large expansion of an oil sands mine (adding 150 kbd at peak) operated by Suncor, in partnership with ExxonMobil, Imperial, CNOOC, and Sinopec. The project is currently under development, with first production expected in 2025. At the time of the FID in 2021, the project's breakeven oil price was USD 34.7/bbl.
- **Christina Lake Phase 3**: A small additional phase of an in situ oil sands project (adding 15 kbd at peak) operated by MEG Energy. The project is currently under development, with first production expected in 2026. At the time of the FID in 2023, the breakeven oil price was USD 38.7/bbl.
- **Bay du Nord**: A large greenfield, offshore conventional field (140 kbd at peak) operated by Equinor in partnership with BP. Rystad forecasts an FID in 2028, with a breakeven oil price of USD 43.8/bbl at that time.
- **Aspen Phase 1**: A medium-sized greenfield, in situ oil sands development operated by Imperial, in partnership with ExxonMobil. Rystad forecasts an FID in 2029, with a breakeven oil price of USD 51.2/bbl at that time.

Cumulative cash flow forecasts for the four projects are shown in Figures 10 to 13, discounted at a rate of 10% (nominal). As shown, the lower-demand scenarios worsen the economics, both lowering the eventual return and delaying the breakeven point, albeit to differing degrees between the four projects.

Mildred Lake West and Bay du Nord narrowly fail to break even with NZE demand at a 10% discount rate. APS demand delivers commercial returns for these two projects, with breakeven achieved about 2 years later with APS demand than with STEPS and the base case. Christina

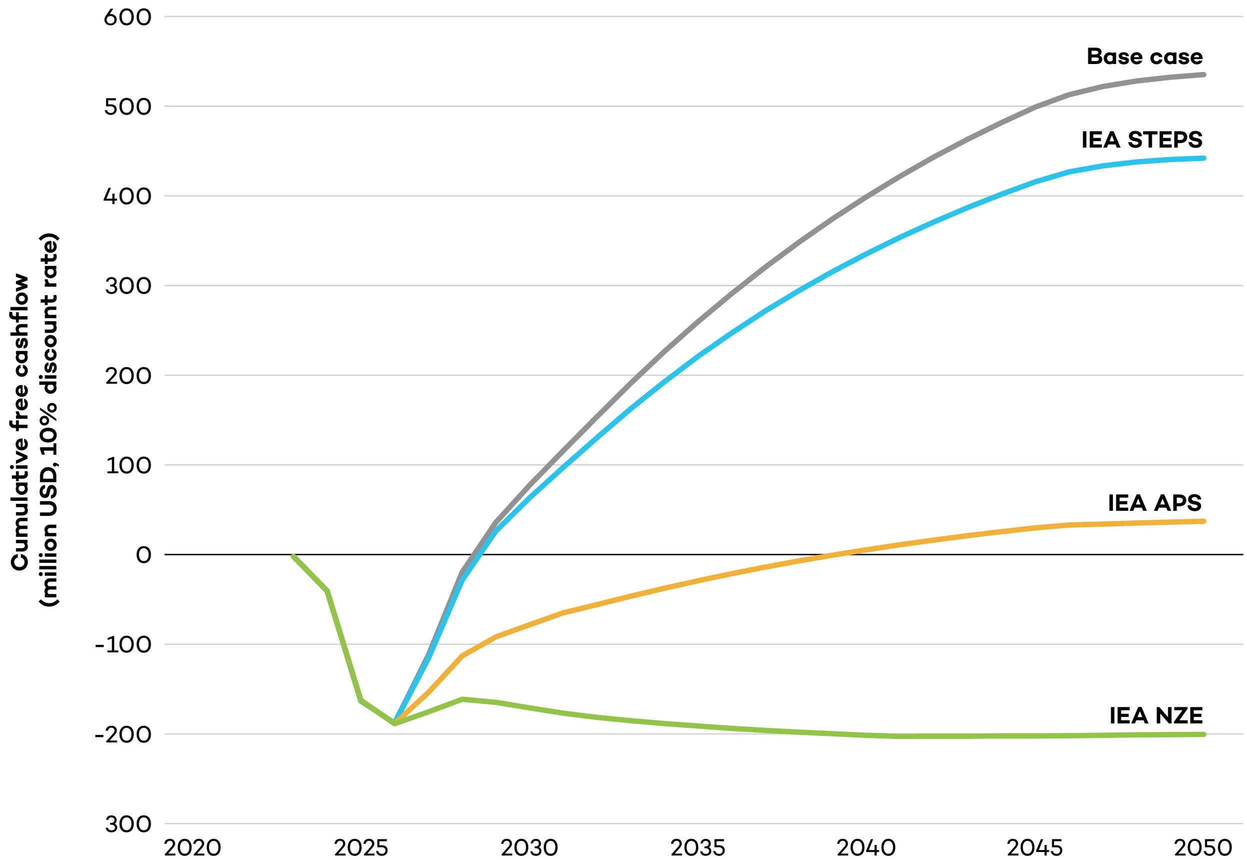
Lake 3 sees a very negative outcome with NZE demand and a mildly positive one with APS; breakeven occurs 9 years later with APS than with STEPS, leaving the project exposed to transition risk. Aspen 1 fails to break even with either NZE or APS demand.

Figure 10. Cumulative discounted free cash flow (10% discount rate), Syncrude Mildred Lake Extension West



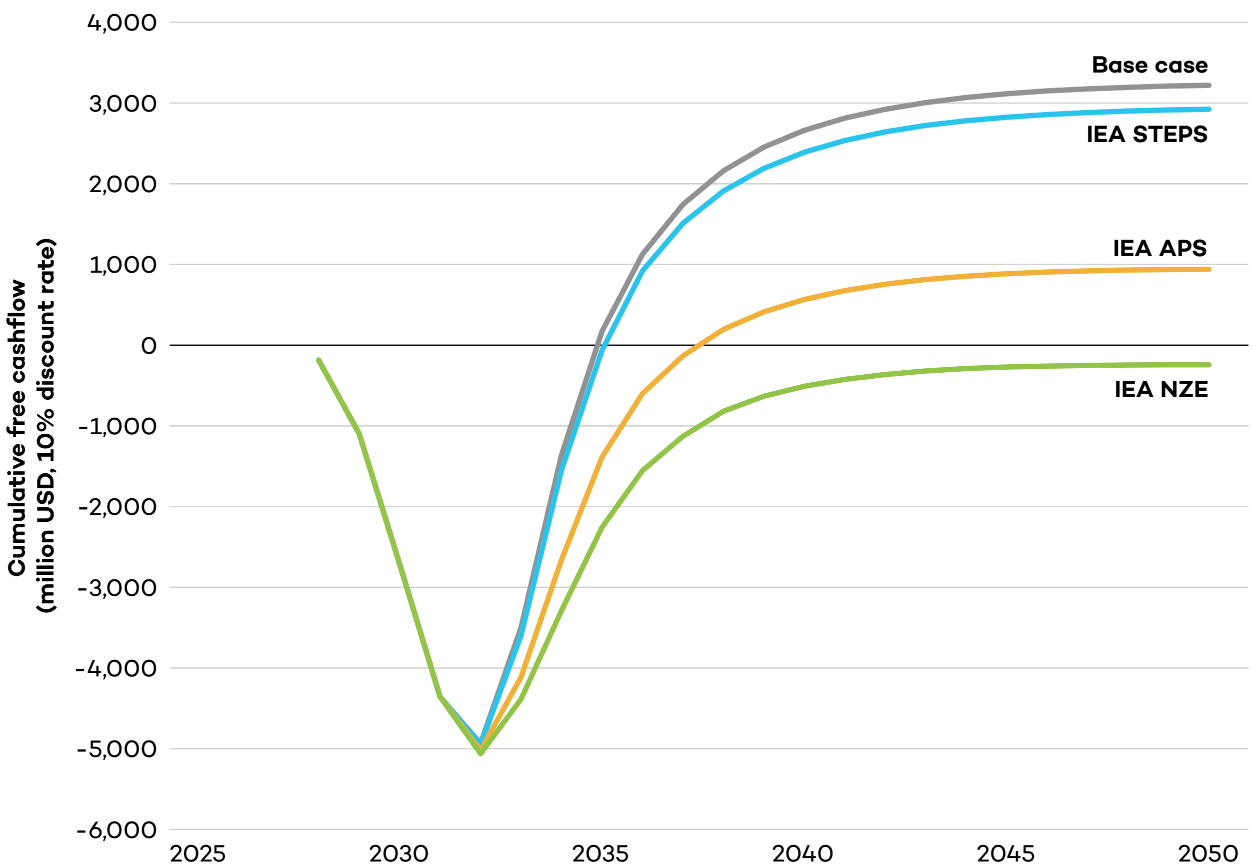
Source: Author's analysis, using data from Rystad Energy UCube, 2024.

Figure 11. Cumulative discounted free cash flow (10% discount rate), Christina Lake Phase 3



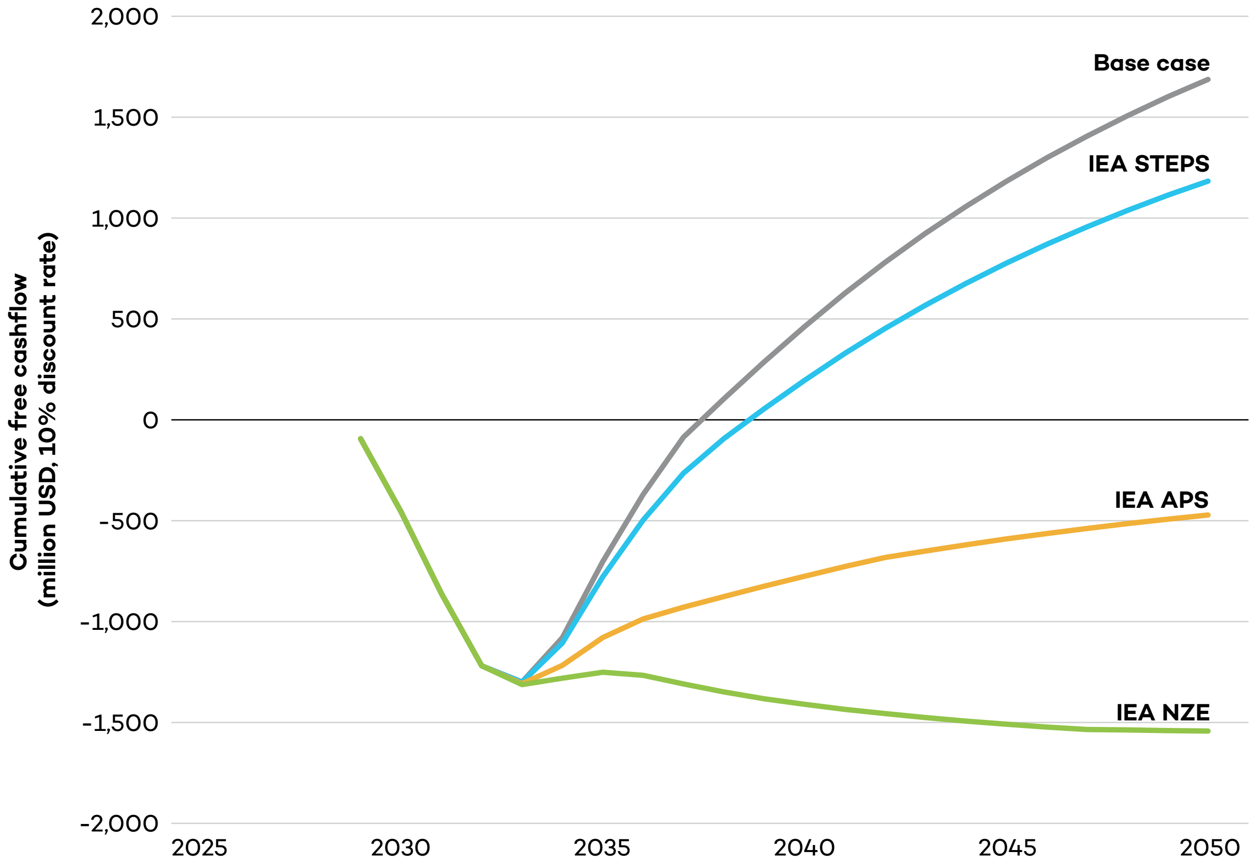
Source: Author's analysis, using data from Rystad Energy UCube, 2024.

Figure 12. Cumulative discounted free cash flow (10% discount rate), Bay du Nord



Source: Author's analysis, using data from Rystad Energy UCube, 2024.

Figure 13. Cumulative discounted free cash flow (10% discount rate), Aspen Phase 1



Source: Author's analysis, using data from Rystad Energy UCube, 2024.

4.2 Impact on Aggregate Project Investments

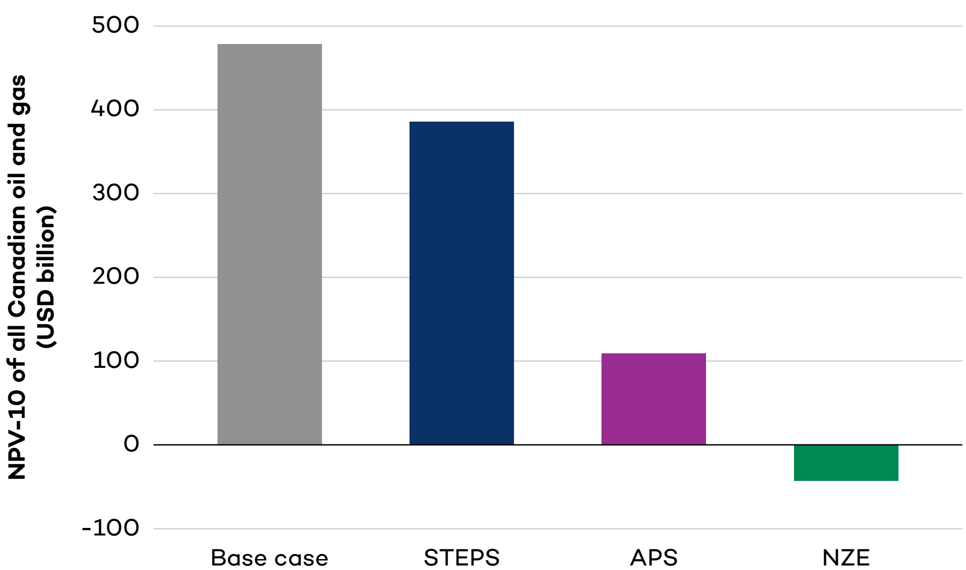
These results are now combined across the Canadian oil and gas industry. NPV is the cumulative total of cash flows: the value on which each project converges in the graphs above. NPV measures the economic performance of investments. The results are shown in Table 7 and Figure 14 for all investments in Canadian oil and gas fields.

Table 7. NPV_{10} of Canadian oil and gas production at different demand levels (USD billion)

	Producing	Under development	Fracking developed	Discovered, undeveloped	Undiscovered	Total
Base case	320	24	75	66	-2	478
STEPS	288	22	55	24	-3	386
APS	123	8	21	-39	-4	109
NZE	32	-1	6	-75	-4	-43

Source: Author's analysis, using Rystad Energy UCube, 2024.

Figure 14. NPV_{10} of Canadian oil and gas production at different demand levels



Source: Author's analysis, using Rystad Energy UCube, 2024.

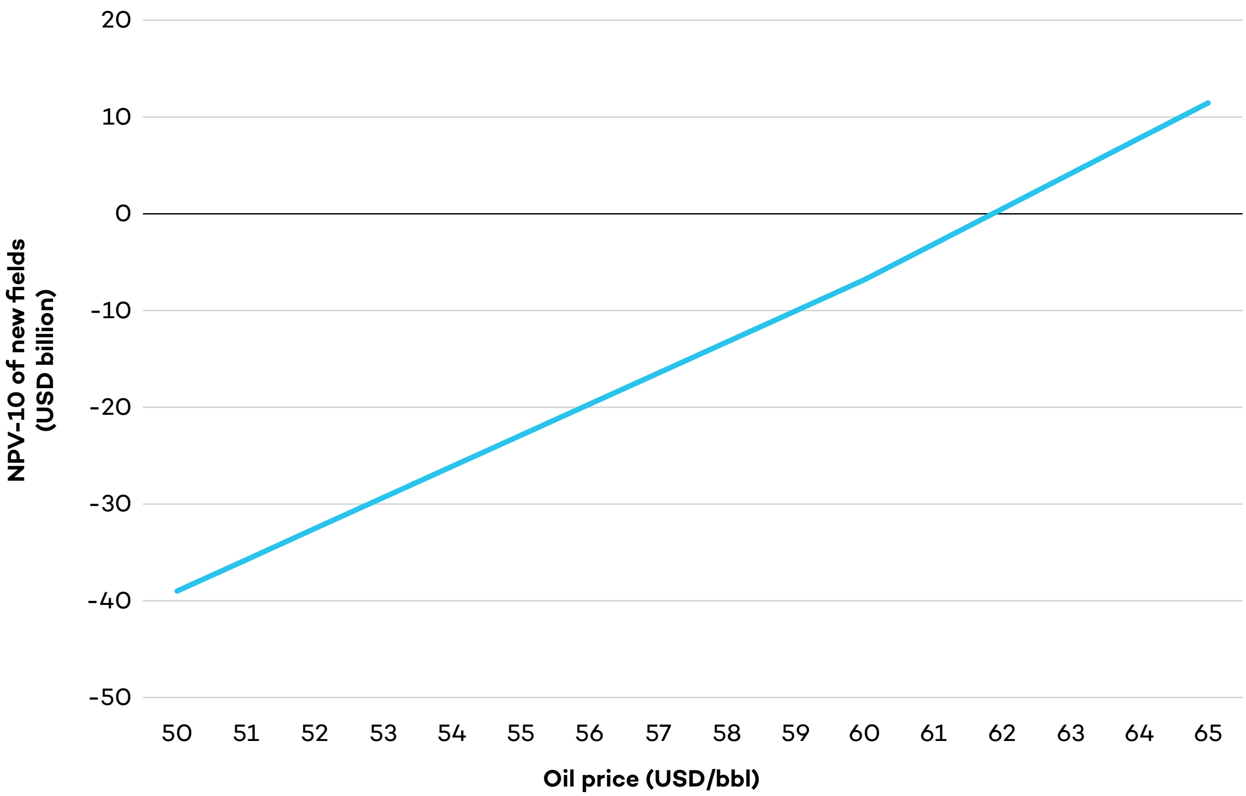
In Rystad's base case, representing industry expectations, the NPV_{10} of future Canadian oil and gas fields is nearly USD 480 billion. With STEPS demand, it is 19% lower than this, and with APS, it is 77% lower (i.e., with APS, most value is lost compared to expectations). With NZE demand, total NPV_{10} becomes negative: a liability rather than an asset.

At both APS and NZE demand levels, the NPV_{10} of undeveloped fields is negative, meaning that proceeding with new fields destroys rather than creates value across the industry as a whole. While some individual new fields might have positive returns, investments overall fail to generate commercial returns at these demand levels.

Note again that the positive NPV_{10} in producing fields in all scenarios, and under-development fields in all except NZE, does not necessarily indicate that they deliver commercial returns but rather that their discounted future cash flows are positive. The fields may be making sub-commercial returns on the capital already invested (see Sections 1.3 and 2.3).

Even with STEPS demand, the NPV_{10} of undeveloped fields (discovered plus undiscovered) is just 5% of the total NPV_{10} of all fields. This implies that a reduction in demand well short of the APS scenario could destroy this residual value. To test this, Figure 15 plots the NPV_{10} for undeveloped oil and gas fields for flat oil price scenarios between USD 50/bbl and USD 65/bbl.[30] We see that developing new fields becomes value-destructive at prices below USD 62/bbl.

Figure 15. NPV_{10} of all undeveloped Canadian oil and gas fields at a range of flat (real) oil price scenarios



Source: Author's analysis, using Rystad Energy UCube, 2024.

[30] Gas prices are assumed to be linked to oil prices in the Rystad Energy UCube. Unlike other parts of this report, Figure 15 does not assess oil and gas separately, but instead relies on the price linkages in the UCube model.

4.3 Impact on Companies and the Financial System

As noted in Section 2.5, NPV of a company's future operations provides the best guide to valuing the company (although other factors are also relevant). The NPV analysis is now applied only to the operations (on an equity ownership basis) of each of the four largest Canadian oil and gas companies, as shown in Table 8, to illustrate how their valuation may change. For Imperial Oil, only the publicly traded portion is shown (i.e., excluding ExxonMobil's 69.6% share of the company).

Table 8. NPV_{10} of the largest Canadian oil and gas companies' production at demand levels (USD billion)

	CNRL	Cenovus	Suncor	Imperial (publicly traded part)
Base case	98	45	35	5
STEPS	85	37	26	4
APS	37	7	-12	-2
NZE	10	-11	-32	-5

Source: Author's analysis, using Rystad Energy UCube, 2024.

At NZE demand levels, Cenovus, Suncor, and Imperial all have negative total NPV_{10} (i.e., their aggregate internal rates of return are below 10% in nominal terms), suggesting that investors could get better returns by investing elsewhere. Suncor and Imperial also have negative NPV_{10} at APS demand levels. Even where NPV_{10} is positive in these two scenarios (Cenovus with APS demand and CNRL with APS and NZE demand levels), it is with total value reduced to a fraction of what it is under current expectations.

While sub-10% returns do not immediately make companies unable to repay their loans, increasing financial stress adds to the default risk. If this occurred, it would raise risks for broader financial stability. In a vicious circle, reduced value can increase borrowing costs for these companies, adding to their financial stress. According to analysis by InfluenceMap (2024), Canada's banking sector is more than twice as exposed to fossil fuels as its U.S. and European counterparts. Seventeen percent of the corporate lending and bond and equity underwriting at the Big Five Canadian banks—CIBC, TD Bank, Scotiabank, RBC, and BMO—is to fossil fuels, with 68% of that exposure being to Canada-based oil and gas companies. An assessment by the Bank of Canada and the Office of the Superintendent of Financial Institutions (2022) estimates that the probability of default in 2050 will increase by 150% for conventional oil extraction and 400% for oil sands, compared to current levels.

The loss of value will also concern the companies' shareholders. Companies involved in the extraction or long-distance transport of oil and gas have market capitalization of CAD 627 billion, about 16% of the Toronto Stock Exchange (2024).

In addition to these impacts on oil companies and their shareholders, this loss of value can have wider consequences, as outlined in Section 1.4. Reduced value of companies can cause financial shocks by reducing the value of asset owners' portfolios. Oil companies' stress can spread across the economy through supply chain linkages (Cahen-Fourot et al., 2021) and through financial contagion (Roncoroni et al., 2021). Tighter economics may also reduce the capital available for reinvestment, with impacts on future economic output.

4.4 Impact on Government Revenues

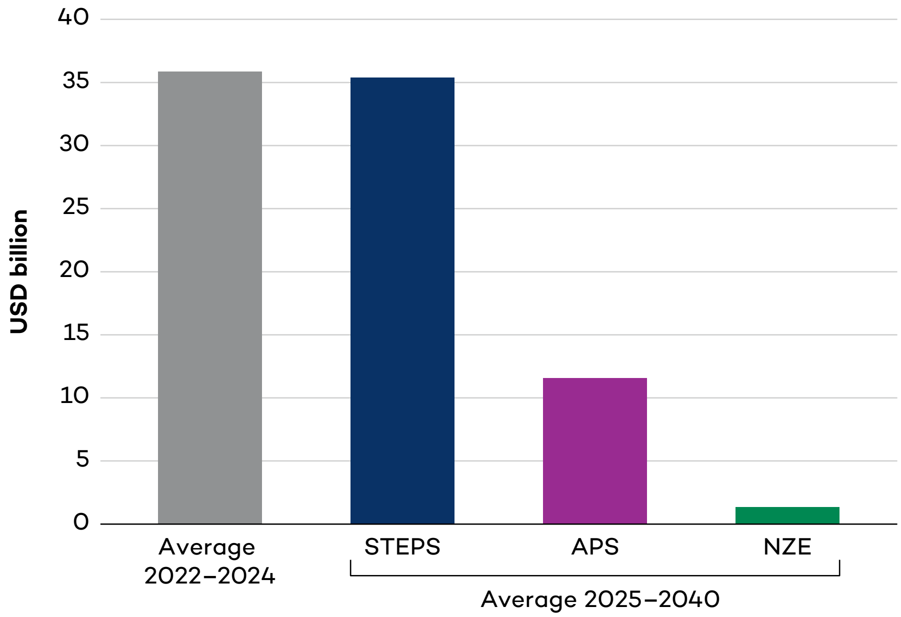
Reduced oil and gas demand and prices will also have an impact on annual government revenues. The results are shown in Figure 16, aggregated across all Canadian oil and gas fields and in Table 9, aggregated for each stage of field development. The more relevant comparator here, rather than the UCube base case, is the average government revenue over the last 3 years of USD 36 billion per year; this is shown in Figure 16.

Table 9. Annual average government revenues (combined federal and provincial, undiscounted) from Canadian oil and gas production (2025–2040) in different scenarios (USD billion)

	Producing	Under development	Fracking developed	Discovered, undeveloped	Undiscovered	Total
STEPS	22.6	2.3	6.6	4.0	-0.1	35.4
APS	8.0	0.9	3.0	-0.3	-0.1	11.6
NZE	1.7	0.4	1.5	-2.1	-0.1	1.3

Source: Author's analysis, using Rystad Energy UCube, 2024.

Figure 16. Annual average government revenues (combined federal and provincial) from Canadian oil and gas production (2025–2040) at different demand levels



Source: Author's analysis, using Rystad Energy UCube, 2024.

Government revenues are shown to be significantly vulnerable to declining oil and gas demand during the energy transition. STEPS demand levels show revenues that are comparable to recent history, while APS demand revenues are 68% lower and NZE demand revenues are 96% lower. At NZE demand, revenues are even lower than they were in 2020 during the COVID-19 pandemic, when the UCube estimates USD 2 billion in revenues. At both APS and NZE demand levels, government revenues from new fields are negative: rebates and subsidies exceed tax payments for these fields, even before taking into account the indirect effects.

The potential reductions in revenues will be of particular concern in Alberta, Newfoundland and Labrador, and Saskatchewan, where oil and gas provide about 33%, 7%, and 4% of government budgets, respectively (Section 1.1). The most recent periods of sustained low oil prices, such as those experienced in 2015/2016 and 2020, tested the Canadian and Alberta governments with severe fiscal repercussions. The Government of Alberta (2021) reported a deficit of nearly CAD 17 billion for the 2020/2021 fiscal year, leading to cuts in public spending.

Again, this assessment understates the full fiscal impact of stranded oil and gas assets. For example, the loss of jobs will lead to reduced income tax payments and increased social support. The economic impacts outlined above will also create strong political pressure for greater subsidies to producers, as history has demonstrated (Dusyk et al., 2023). Following the COVID-related oil price-drop in 2020, the Canadian government doubled its oil and gas subsidies to at least CAD 1.9 billion, while the Alberta government provided an extra CAD 1.3 billion in subsidies for the fiscal year 2020/2021 (Corkal, 2021; McKenzie et al., 2022). Tax relief and temporary royalty adjustments were implemented to maintain production and investor interest, while direct transfers were also implemented to increase investments in infrastructure and technology (Corkal, 2021).

These risks to fiscal revenues highlight the importance of diversifying sources of government revenue and the broader economic base. Investments in alternative sectors can both offset the fiscal losses and create new jobs (Clean Energy Canada, 2023). Economic transformation takes time, suggesting an urgent need to make progress before the global energy transition advances further. In addition, investments in diversification and enabling a just transition will be much harder if governments wait until they are more fiscally stressed before acting.

4.5 The Effect of U.S. Tariffs

All else being equal, U.S. tariffs reduce the profitability of most Canadian oil and gas fields, either because producing companies have to sell to U.S. refiners at a lower price or because they incur additional transport costs of shipping elsewhere. In the cash flow projections of Section 4.1, the cumulative cash flow under tariffs would thus increase at a slower rate once production starts: the latter parts of the graphs would slope more gradually and the breakeven point would be pushed later in time—or possibly not achieved at all. Correspondingly, the NPV_{10} of all oil and gas fields would be lower, and hence, so would the financial performance of companies.

U.S. tariffs reduce profitability and revenues for industry in all scenarios, including the base case. Decreased demand due to the global energy transition would still reduce the NPV of future production compared to scenarios with higher demand, with or without tariffs; however, the specific amount by which it does so with tariffs in place will depend on market effects that remain uncertain (Section 2.6). As noted in Section 3.5, one unknown is by how much investments in Canadian production will be reduced due to tariffs. Again, any new investments that do proceed would face greater risk under tariffs than outlined in this report—that is, the quantitative estimates here may understate the economic risks facing Canadian oil and gas production during the global energy transition.

Government revenues would also be lower following U.S. tariffs, although the effect would be less than on projects' NPV and the industry's financial performance. This is because most revenues come from royalties, which are charged as a percentage of gross income rather than profits. Hence, this report's findings related to the impact of reduced oil and gas demand on governments' revenues will be less affected by U.S. tariffs than the findings on NPV.

5.0 Economic Effects of Stopping New Field Development

The previous section found that new fields deliver negative NPV_{10} and negative government revenues at both APS and NZE demand levels. At STEPS demand levels, NPV_{10} and government revenues are low and subject to downside risk if demand falls below this level. This raises the question of what would happen if no new fields were to be developed. This has been proposed previously as a solution: von Dulong et al.'s (2023) review of stranded assets literature suggests that near-term climate policy could focus on directly restricting new fossil fuel investments and redirecting that capital toward clean energy. This could be more effective in some cases than introducing prices on carbon, which tend to disproportionately impact lower-income consumers (when implemented without sufficient complementary policies to mitigate this regressive effect) and often face political resistance in practice.

This section examines the outcome of two possible policy interventions. First, Canadian provincial and federal governments stop any new fields from being developed. The analysis thereby assumes no new conventional or oil sands projects receive an FID and no new acreages are opened to fracking, beyond those where the infrastructure is already built. In practice, this could be achieved in several ways, with the most direct being for the relevant provincial and/or federal regulator to deny the project permits required before a company can develop any new fields.

Second, Canadian governments use this example diplomatically to persuade other governments to do the same. To assess the impact of such an approach, this analysis assumes that 10% of production from new fields outside Canada does not come online, spread evenly across the cost curve.

5.1 Equilibrium Price Analysis

Repeating the analysis of the preceding sections, the first step is to use the stranded assets methodology of Section 3 to find the equilibrium prices resulting from the policy interventions in the three demand scenarios.

Restricting Canadian supply will lead to some substitution of the lost volumes by alternative suppliers. The marginal price will then increase as supplies from higher in the cost curve are added to clear the market (assuming low-cost suppliers in OPEC do not increase production—see Section 2.7 and Box 4). In the real world, this substitution effect is partial: higher prices also reduce demand, leading to a new equilibrium with lower volume consumed (RedLine Database, 2024). In this report's methodology, however, demand is taken as a given, so in this theoretical case, 100% substitution occurs, which leads to an overestimation of the equilibrium price.

Table 10. Equilibrium oil prices by demand scenario and effect of policy interventions (USD/bbl)

	STEPS	APS	NZE
No intervention	66.3	47.1	36.8
Stop new field development	72.5	47.6	36.9
Diplomacy to persuade other governments	106	48.5	37.4

Source: Author's analysis, using Rystad Energy UCube, 2024, 2024.

Table 11. Equilibrium gas prices by demand scenario and effect of policy interventions (USD/kcf)

	STEPS	APS	NZE
No intervention	3.77	3	2.54
Stop new field development	3.9	3.03	2.54
Diplomacy to persuade other governments	3.92	3.03	2.54

Source: Author's analysis, using Rystad Energy UCube, 2024.

In most cases, the price impact of the policy interventions is modest. At APS and NZE demand levels, gas prices barely change at all, because less North American gas supply is exported as LNG as a result. The one case where prices increase significantly is under the diplomacy intervention if demand follows STEPS. The equilibrium oil price rises to USD 106/bbl in this case. The reason is that this is too much of a supply restriction compared to robust demand levels, providing a useful reminder of the importance of simultaneously adopting policies to reduce both supply and demand.

5.2 Economic Outcomes

The tables and figures below repeat the analyses of Section 4 using the equilibrium prices above, where new field development is stopped in Canada and where 10% of new field development is also stopped internationally. The following subsections reflect on the implications of these results.

Table 12. Impact of policy interventions on NPV_{10} of Canadian oil and gas production at different demand levels (USD billion)

	STEPS	APS	NZE
No intervention	386	109	-43
Stop new field development	427	158	38
Diplomacy to persuade other governments	737	166	43

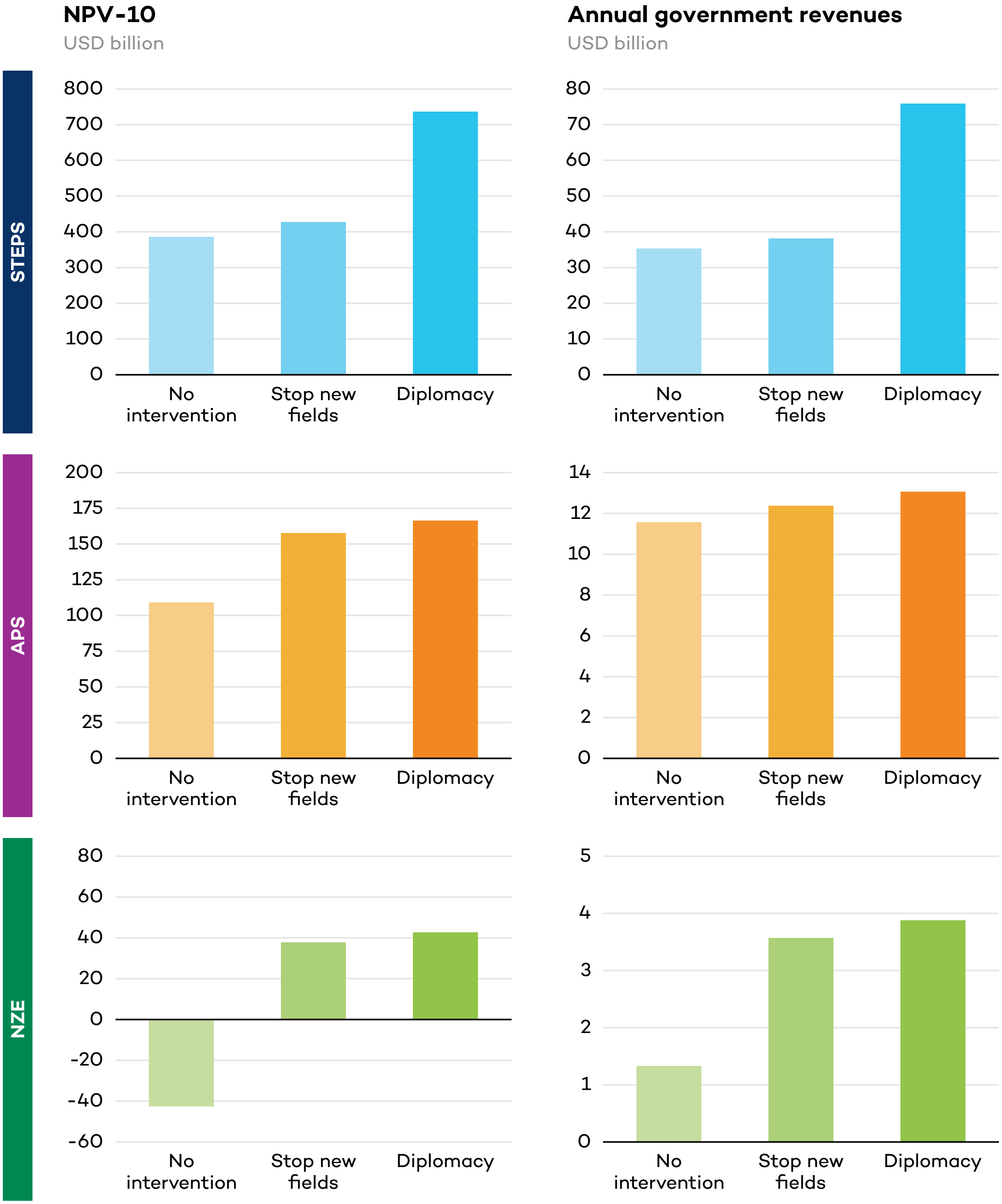
Source: Author's analysis, using Rystad Energy UCube, 2024.

Table 13. Impact of policy interventions on average annual government revenues (combined federal and provincial, undiscounted) from Canadian oil and gas production (2025–2040) at different demand levels (USD billion)

	STEPS	APS	NZE
No intervention	35	12	1
Stop new field development	38	12	4
Diplomacy to persuade other governments	76	13	4

Source: Author's analysis, using Rystad Energy UCube, 2024.

Figure 17. Impact of policy interventions on NPV_{10} (left-hand panels) and undiscounted average annual government revenues 2025–2040 (right-hand panels) of Canadian oil and gas production at different demand levels (USD billion)



Source: Author's analysis, using Rystad Energy UCube, 2024.

5.3 Ending New Field Development in Canada

Since new fields in aggregate deliver negative NPV_{10} at the APS and NZE demand levels, total NPV_{10} is greater if new fields are not developed. More strikingly, stopping new fields also increases NPV_{10} of existing fields. This is because the production restriction raises the equilibrium price by a small amount, thereby increasing the profitability of all fields. Overall, stopping new field development returns the sector to positive valuation at NZE demand levels and increases value at the other two scenarios' demand levels. Even with STEPS demand, NPV_{10} is higher without new fields than with them. This is because the forgone profit from the new fields is outweighed by higher profitability in existing fields due to the higher prices from avoiding oversupply.

The above analysis indicates that the industry as a whole delivers greater value (and higher profits) if it develops no new fields than if it continues with business as usual. Why, then, would it continue investing in new fields? Many individual new projects have positive NPV_{10} if demand follows the STEPS scenario, and some do if it follows APS or NZE. In these cases, the respective companies will often (depending on the other fields in their portfolios) be better off if they develop the fields than if they do not.[31] But NPV_{10} for the industry as a whole is worse if new fields are developed. This is a collective action problem, which makes a good case for government intervention. And given the impact of stranded assets on the wider economy (Sections 1.4 and 4.4), such a policy could serve the public benefit, not only the interests of oil companies.

Indeed, this dynamic characterizes much of the early decades of the modern oil industry: individual producers would maximize their own production, leading to an aggregate oversupply and crashing prices (see, e.g., Fisher 2022). For this reason, public bodies stepped in to manage the market chaos, notably the Texas Railroad Commission, which, from 1919 to the 1960s, prorationed oil production to sustain higher prices. Later, OPEC took over that role, with more mixed success (Colgan 2014, 2020).

Nor is this a new idea in the Canadian context. In 2018, the Government of Alberta imposed a mandatory restriction on production levels, cutting the province's production by nearly 9%. It did so in response to low prices being received by all producers due to overproduction relative to pipeline capacity.[32] Industry reaction was mixed, with some companies supporting and others opposing the intervention (Bellefontaine, 2018). While that measure was temporary—it lasted 2 years—the same principle could apply over the longer term by restricting production to avoid oversupply relative to declining markets, thereby improving the economics for all. And stopping new fields before major capital investment has occurred is an economically preferable policy compared to restricting the production of all fields because the former approach will not cause significant financial losses. Moreover, that uninvested capital would remain available to support alternative industries, including those aligned with the global energy transition.

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31 In addition, company decision-makers may be influenced by short-term performance horizons or selection bias when choosing modelling.

32 As another example, Canadian provinces routinely restrict production to sustain higher prices in the dairy industry.

The policy intervention of stopping new fields would also increase government revenues by a factor of 2.7 at NZE levels of demand or more modestly in the other two demand scenarios.

Box 4. Would OPEC replace reduced Canadian production?

One uncertainty in the results above is whether any reduced Canadian production would lead to an increase in OPEC production, which—if applied one-for-one—would cancel out the expected Canadian NPV and revenue gains due to the price effect.

As noted in Section 2.7, Saudi Arabia is the only member of OPEC (and OPEC+) with the potential to significantly increase production to gain greater market share. Saudi strategic decisions on production are generally motivated by either asserting greater influence over the oil market (including by discouraging other OPEC or OPEC+ members from free riding on its production restraint) or maximizing its long-term revenues. While the former dynamics cannot be predicted, assessing Saudi economic interests through a simple indicative calculation is possible.

Stopping new Canadian oil field development would reduce Canadian production over 2025–2040 by 5.6 billion barrels (an average of 950 kbd over the 16-year period). The price effect of this is shown in Table 10: with STEPS demand levels, it would sustain global oil prices at an average of USD 72.5 per barrel, compared to the USD 66.3 that would result if new fields continue to open.

The Rystad Energy UCube projects Saudi production of 70 billion barrels over that period and total capital and operating expenditure of USD 782 billion, equivalent to about USD 11.2/bbl. Thus, if Saudi Arabia were to fully replace the lost Canadian production, it would increase its oil production by 5.6 billion barrels, or 8%. The effect of this extra production would reduce the oil price to below USD 66.3/bbl, and its net income from each barrel would fall, on average, from USD 61.5 to below USD 55.3/bbl, a reduction of more than 10%. In other words, Saudi Arabia would be economically worse off by seeking to replace the Canadian production.

Saudi Arabia's economically optimal course would be to not replace the production, even with a STEPS level of demand. If demand is lower due to the global energy transition, there will be even less incentive for Saudi Arabia or OPEC to replace Canadian production.

5.4 Diplomacy to Persuade Other Countries Not to Develop New Fields

What happens if Canada not only ends new field development but also starts to persuade other countries to follow suit? Table 13 shows that doing so in all three scenarios increases NPV_{10} and government revenues. The effect is largest at STEPS demand levels (although the numbers in the table overstate this because the fixed-demand approximation boosts price by more than would occur in the real world, as explained in Section 5.1).

These economic improvements are as we would expect: less production by competitors leaves more room in markets for Canadian production. All incumbents benefit economically from environmental rules and norms that make it harder for new entrants to join the market (Keohane et al., 1998). Indeed, as the world moves from an age of oil scarcity to one of abundance (Dale & Fattouh, 2018), Verbruggen and van de Graaf (2015) suggest that the geopolitics of oil is now about seeking to leave other suppliers' oil in the ground.

One way to do this is through leading by example: those who act first gain both moral legitimacy and diplomatic heft. This is the logic behind the growing popularity of "climate clubs" (van Asselt & Newell, 2023), where coalitions of governments come together to lead in climate action, earning influence over others and progressively building the coalition. Examples include the Powering Past Coal Alliance (which is co-led by Canada and the United Kingdom), the Clean Energy Transition Partnership (of which Canada is a member), and the Beyond Oil and Gas Alliance (of which Quebec is a member).

Governments join climate clubs because they serve their material interests and assert their values and convictions (Blondeel et al., 2020). The analysis above suggests that it may be in Canada's economic interests—as well as consistent with its self-identity as a climate leader—to end new oil development and encourage others to do the same.

Figure 3 illustrates why Canada's economic interests are served by adopting such a position—Canada's oil production is at the high end of the cost curve. Maximizing supply as demand falters will lead to lower prices, which would have a greater proportional effect on Canadian margins than those in other countries (a price reduction will take away a greater proportion of the smaller margins) and are more likely to push Canadian production into uncommercial returns. Instead, Canada's best outcomes are achieved if global supply declines alongside demand.

5.5 The Effect of U.S. Tariffs

The analysis above is based on market fundamentals in the absence of U.S. tariffs on Canadian imports. What would be the effect of the policies discussed in this section if U.S. tariffs were in place?

U.S. tariffs would not change the finding that in the APS and NZE scenarios, stopping new field development would increase NPV_{10} of—and government revenues from—Canadian oil and gas production. This is because new, undeveloped fields have negative NPV_{10} and deliver negative government revenues in these scenarios, even in the absence of tariffs (Tables 10 and 12). Tariffs would reduce these values further, so preventing these fields from opening would have an even bigger effect on increasing overall NPV_{10} and revenues in these scenarios.

In the STEPS scenario, the effect of tariffs is more complex. In the non-tariff case, the finding that stopping new field development delivers greater NPV_{10} and government revenues arises because the effect on existing fields of slightly higher prices outweighs the effect of removing gains from new fields. As discussed in previous sections, the precise effects of tariffs on oil and gas markets will not be fully observable for months, even if the policy environment remains stable. However, as discussed in Section 3.5, we can anticipate that the general effect of tariffs will be to move the marginal breakeven point rightward in the cost curve. And since the slope of the cost curve increases further to the right (Figures 5, 7, and 9), this means price effects would become increasingly important compared to volume effects. Therefore, the balance of effects seen earlier is likely to intensify. That is, stopping new fields is likely to have a greater positive effect on NPV and revenues than without tariffs.

Furthermore, the effect of successful diplomacy to reduce new production elsewhere will always be positive for Canadian economic outcomes, with or without tariffs.

6.0 Conclusions

We do not know what the future holds. The best we can do to assess such economic risk is to consider various possible futures that may unfold and their implications. This is particularly important for oil and gas exporters like Canada, subject to changes in demand beyond their borders, which can have a profound domestic economic impact.

It is possible that the world's governments introduce no new climate policies and that the future looks like the STEPS scenario. In that event, there would be worsening physical impacts of climate change (and a range of related impacts on people's health, the local environment, and the economy as a whole), though less economic transition risk, specifically for Canadian oil and gas production. It would, however, be unwise from an oil and gas perspective to think that this is the only possible future. There is at least a meaningful chance that governments do what they have said they will do, either individually in net-zero pledges (the APS scenario) or collectively in the Paris Agreement goals (the NZE scenario), especially as worsening climate impacts spur action. And there is a significant chance that they will at least move some way toward these things. After all, the STEPS projection of future oil and gas demand under extant policies has been successively revised downward over the last seven editions of the IEA's *World Energy Outlook* (Section 1.2).

If demand is even partially lower than industry expectations, there are risks of oil and gas investments and companies losing value, as well as governments losing revenue. If demand is significantly lower, there is a risk of wider economic harm, including potentially destabilizing the financial system.

To be prepared for such possible futures, the biggest policy implication is that Canadian governments should urgently work to reduce economic dependence on oil and gas production and make a comprehensive plan for economic diversification and just transition (Cosbey et al., 2021; Dusyk et al., 2023). This need is most pressing for Alberta, Newfoundland and Labrador, and Saskatchewan, given their high economic vulnerability to the risks outlined in this report. If governments wait until they are certain that a faster transition is underway, by that point, their fiscal revenues may be reduced to the extent it is harder to respond.

A second implication is to revive an idea that is almost as old as the oil industry: for government to take an active role in restraining production to improve the economics of the whole industry. We have seen that the industry and governments would be better off economically if no new oil and gas fields were opened in Canada, even if Canada adopts such policies unilaterally. And with growing international interest in this idea, such a policy would give Canada an opportunity for diplomatic leadership, to build an international norm that would further strengthen Canada's position.

There is strong scientific evidence that no new oil and gas fields should be opened if the world is to limit warming to 1.5°C (Green et al., 2024; IEA, 2021; Trout et al., 2022). This report finds that the economic case for Canada points in the same direction.

For a long time, it has been assumed that Canada's best economic interests lie in the continued expansion of oil and gas production. As global energy markets shift, that assumption may no longer be true.

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Appendix A. Oil and Gas's Role in the Economy

Table A1. Oil and gas contributions to Canadian and provincial economies, 2023

		Canada	Alberta	Saskatchewan	Newfoundland & Labrador	British Columbia	Source (Statistics Canada)
GDP (CAD billion)	Oil & gas	71.4	55.7	6.83	4.19	4.64	2024b, 2024c
	All sectors	2,380	344	77.9	29	309	2024d, 2024c
	O&g share	3.0%	16.2%	8.8%	14.4%	1.5%	
Jobs (thousands)	Oil & gas	93.4	86	2.4	1.9	2.5	2024e
	O&g support	56.8	50.0	4.7	1.4	2.9	2024e
	All sectors	20,500	2,500	604	231	2,880	2024e
	O&g share	0.7%	5.4%	1.2%	1.4%	0.2%	
Government revenue (CAD billion)	Royalties	23.1 [33]	25	0.9	0.6	0.9	2024f, 2024a
	O&g other	11	no data	no data	no data	no data	2024f
	All sources	4,850	75	22	8.5	75.1	2024g, 2024a
	O&g share	0.7%	33%	4%	7%	1%	

Source: Compiled by author.

[33] Federal and provincial.

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